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PSEG
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VIA BPU E-FILING SYSTEM & OVERNIGHT MAIL

June 1, 2018

In the Matter of Public Service Electric and Gas Company's 2018/2019
Annual BGSS Commodity Charge Filing for its Residential Gas Customers
Under its Periodic Pricing Mechanism

Docket No. GR_____________

Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
Post Office Box 350
Trenton, New Jersey 08625-0350

Dear Secretary Camacho-Welch:

Enclosed for filing please find an original and two copies of Public Service Electric and Gas Company's ("Public Service," "PSE&G" or "the Company") Motion, Testimony of David F. Caffery and supporting attachments in the above-referenced matter which has also been uploaded to the Board of Public Utilities E-Filing system. In this filing, Public Service is requesting a decrease in Annual BGSS gas revenues of approximately $24.8 million (excluding losses and New Jersey Sales and Use Tax, SUT) to be implemented for service rendered on and after October 1, 2018 or earlier, should the Board deem it appropriate. The impact of the change on a typical residential heating customer using 165 therms per month during the winter months and 1,010 therms on an annual basis is an annual decrease of approximately 1.3%.

This filing and the proposed BGSS rate is in accordance with the Board's January 6, 2003 Order Approving BGSS Price Structure, Docket No. GX01050304. Moreover, this filing includes the Minimum Filing Requirements as included in an April 22, 2003 Settlement under Docket No. GR02090702 approved by the Board on June 20, 2003.

Respectfully submitted,

Matthew Weissman

C Attached Service List (electronic)

BGSS 2018-2019

Docket No. GR18________________

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1. <u>Motion, Supporting Testimony & Tariff Modifications</u>

Motion – dated June 1, 2018

Testimony of David F. Caffery – Attachment A

Tariff Sheets – Attachment B

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S 2018/2019 ANNUAL BGSS COMMODITY CHARGE FILING FOR ITS RESIDENTIAL GAS CUSTOMERS UNDER ITS PERIODIC PRICING MECHANISM AND FOR CHANGES IN ITS BALANCING CHARGE	)))))))	MOTION DOCKET NO. GR____________

Public Service Electric and Gas Company (PSE&G or the Company), a public utility of the State of New Jersey, with its principal offices for the transaction of business at 80 Park Plaza Newark, New Jersey 07101, hereby moves before the New Jersey Board of Public Utilities (Board) as follows:

PSE&G, as a combination electric and gas utility, is engaged in the purchase, transmission, distribution and sale of natural gas for residential, commercial and industrial customers in New Jersey in addition to its electric operations.

GENERIC PROCEEDING ON BGSS PRICE STRUCTURE

1) On January 6, 2003, as the result of a generic proceeding, the Board issued its Order Approving the BGSS Price Structure under Docket No. GX01050304 (BGSS Pricing Structure Order) under which the Board approved procedures providing for annual Basic Gas Supply Service (BGSS) Commodity Charge filings by the Company and all the other New Jersey gas distribution companies by June 1st of 2003 and each year thereafter, and for two potential 5% self-implementing rate increases on December 1st and the following February 1st. These two limited self-implementing rate adjustments would be permitted each year upon notice to the Board and the New Jersey Division of Rate Counsel (Rate

Counsel) on November 1st and January 1st of the estimated change to take effect on December 1st and February 1st, respectively.

MINIMUM FILING REQUIREMENTS

2) In addition, the Board in its January 16, 2003 Order Adopting Provisional Rates under Docket No. GR02090702 reserved an issue to itself by directing that the parties to that proceeding meet to develop mutually agreed upon minimum filing requirements for future annual BGSS Commodity Charge petitions in time for the next petition.

3) The parties to that proceeding agreed on a list of 17 Annual BGSS Minimum Filing Requirements that are applicable to the Company's June 1st Annual BGSS proceedings. The parties included those Minimum Filing Requirements in a Settlement on Annual BGSS Minimum Filing Requirements that was approved by the Board on June 20, 2003. Also, as part of a recent BGSS settlements, Item 18 has been added to address the Company's Gas Supply Plan.

2017/2018 BGSS ANNUAL COMMODITY CHARGE FILING

4) On June 1, 2017, the Company made its 2017/2018 Annual BGSS Commodity Charge filing for its Periodic Pricing Mechanism applicable to its residential gas customers pursuant to the BGSS Pricing Structure Order. The filing was also made in accordance with the above-referenced Minimum Filing Requirements.

5) This Motion was supported by the direct testimony of David F. Caffery, in which he addressed all of the Minimum Filing Requirements which were met and demonstrated that the then current BGSS rate of $0.339408 cents per therm (including losses and SUT) should

be increased to $0.369939 cents per therm (including losses and SUT) effective October 1, 2017 and remain in effect through September 30, 2018.

6) The 2017/2018 filing by the Company included the following:

   a. The Company's estimate that an increase in BGSS revenue of approximately $34.4 million (excluding losses and SUT) would be required for the period of October 1, 2017 through September 30, 2018;

   b. A requested increase for BGSS-RSG Commodity Service from the then-current charge of $0.339408 per therm (including losses and SUT) to a charge of $0.369939 per therm (including losses and SUT).

7) Residential annual bills comparing the current and proposed BGSS charge, pursuant to the 2017/2018 filing were included in the form of public notice attached to that filing as Attachment C. The impact of the requested BGSS-RSG Charge change for a typical residential gas heating customer using 165 therms per month during the winter months and 1,010 therms on an annual basis was an increase in the winter monthly bill of approximately 3.6%; and, on an annual basis the impact was also an increase of approximately 3.6%. Moreover, pursuant to paragraph 10 of the Order Approving Pricing Structure, the public notice also indicated that such proposed rates may be subject to self-implementing rate increases of up to 5% on the ensuing December 1st and February 1st. The impact of such potential self-implementing increases on an average residential bill (1,200 therms annually) was an increase of approximately $8.55 for a winter month on December 1, 2017, and an additional approximate increase of $8.55 per winter month on February 1, 2018.

8) Notice setting forth the Company's June 1, 2017 request for an increase in the BGSS-RSG Commodity Charge was placed in newspapers having a circulation within the Company's gas service territory, and was served on the county executives and clerks of all municipalities within the Company's gas territory.

9) Public hearings were scheduled and conducted in Mount Holly, New Brunswick, and Hackensack on September 11, 14, and 15, 2017, respectively. No member of the public appeared at the public hearings.

10) Subsequent to the June 1, 2017 filing, the Company made a compliance filing on August 30, 2017 in response to the Board's Order in PSE&G's Petition for Approval of Electric and Gas Base Rate Adjustments Pursuant to the Energy Strong Program (Energy Strong Matter) in Docket Nos. ER17030324 and GR17030325. As a result of the settlement of the Energy Strong Matter, the Company's BGSS-RSG Commodity Charge was reduced from $0.339408 per therm (including losses and SUT) to $0.339397 per therm (including losses and SUT) effective September 1, 2017.

11) PSE&G, Staff of the New Jersey Board of Public Utilities ("Board Staff"), and Rate Counsel determined that additional time was needed to complete the review of the Company's proposed BGSS-RSG Commodity Charge. However, the parties also agreed that action with respect to the Company's BGSS-RSG Commodity Charge for the 2017-2018 BGSS year on a provisional basis was reasonable, and therefore agreed to implement the BGSS-RSG Commodity Charge as of October 1, 2017, or as soon as possible upon the issuance of a Board Order approving the Stipulation for a Provisional BGSS Rate (Provisional Stipulation). The Provisional Stipulation was approved at the Board agenda meeting on

September 22, 2017, and the BGSS charge was increased from $0.339397 per them (including losses and SUT) to $0.369939 per them (including losses and SUT) for service rendered on or after October 1, 2017.

12) On October 17, 2017, the Board transmitted the matter to the Office of Administrative Law as a contested case where it was subsequently assigned to the Honorable Jacob S. Gertsman, Administrative Law Judge (ALJ). ALJ Gertsman held a telephonic prehearing conference on December 20, 2017, during which the parties discussed a procedural schedule.

13) Subsequent to the provisional approval by the Board, the Company made a compliance filing on December 21, 2017 in response to the Board's Order in the Company's petition for approval of Gas Base Rate Adjustments Pursuant to its Gas System Modernization Program ("GSMP") under Docket No. GR17070775. As a result of the settlement of the GSMP, the Company's BGSS-RSG Commodity Charge was decreased from $0.369939 per therm (including losses and SUT) to $0.368938 per therm (including losses and SUT) effective January 1, 2018.

14) The December 21, 2017 compliance filing also included notification to the Board that the Company would be providing a two-month bill credit of 15 cents per therm (including SUT) for its BGSS-RSG customers to be effective January 1, 2018 through February 28, 2018 - consistent with the Board's January 6, 2003 Order Approving BGSS Pricing Structure Order, and paragraph 9 of the BGSS Pricing Proposal appended as Attachment A to and approved in the BGSS Pricing Structure Order.

15) On February 21, 2018, the Company filed a notice of an extension of the two-month bill credit described above to be effective March 1, 2018 through March 31, 2018.

16) ALJ Gertsman held a second telephonic prehearing conference on February 22, 2018, during which the Parties discussed the status of the matter.

17) On March 20, 2018, the Company filed a notice of an extension of the three-month bill credit described above to be effective April 1, 2018 through April 30, 2018.

18) The parties subsequently completed their review of the Company's 2017/18 Annual BGSS Commodity Charge filing, and AGREED as follows:

    1. The Company's BGSS Commodity Service, Tariff rate BGSS-RSG of $0.368938 per therm (including losses and SUT) would remain in effect. The Parties agreed that the aforementioned BGSS-RSG Commodity charge would be deemed final.

    2. The current residential customer impact of this action was as follows: MONTHLY – a residential customer using 100 therms per month during the winter months and 610 therms on an annual basis would see no change in the monthly winter bill of $90.81 (based upon rates in effect on February 1, 2018 and assuming that the customer receives BGSS service from PSE&G not including any BGSS-RSG bill credits); ANNUAL – a residential customer using 165 therms per month during the winter months and 1,010 therms on an annual basis would see no change in the monthly winter bill of $902.54 (based upon rates in effect on February 1, 2018 and assuming that the customer receives BGSS service from PSE&G not including any BGSS-RSG bill credits).

    3. Attached as Exhibit C to the stipulation of settlement was the Company's tariff sheet that reflects the current BGSS-RSG Commodity Charge effective January 1, 2018 as well as the 15 cent per therm bill credit in effect through April 30, 2018.

4. The Company agreed to continue to provide electronically to BPU Staff and Rate Counsel, on a monthly basis, the following updated information: 1) the BGSS NYMEX Update Report (also known as S-PSCHART-1); and 2) a monthly report of unitized credits to the BGSS (ISG, Cogeneration, TSG-F, Off System Sales, Capacity Releases, Gas to Electric and Supplier Refunds) and the associated dollar amounts.

5. The Company further agreed to modify the Minimum Filing Requirement for its future BGSS filings in the following manner: (a) Minimum Filing Requirement No. 13 (Affiliate Gas Supply Transactions) shall include a description of the principal terms of the Requirements Contract between PSE&G and PSEG Energy Resources and Trade; and (b) Minimum Filing Requirement Item No. 18 (Gas Supply Plan) shall include a listing of all existing pipeline and storage capacity contracts for which the Company has given notice to extend or terminate during the previous 12 months, and all contracts that were extended under evergreen provisions during the same period.

2018/2019 BGSS ANNUAL COMMODITY CHARGE FILING

19) The Company is making this 2018/2019 Annual BGSS Commodity Charge filing for its Periodic Pricing Mechanism applicable to its residential gas customers pursuant to the BGSS Pricing Structure Order. This filing is also made in accordance with the above-referenced Minimum Filing Requirements.

20) This Motion is supported by the direct testimony of David F. Caffery attached hereto as Attachment A in which he addresses all of the minimum filing requirements that have been met and demonstrates why the current BGSS rate of $0.368938 cents per therm (including

losses and SUT) should be decreased to $0.349579 cents per therm (including losses and SUT) effective October 1, 2018 and remain in effect through September 30, 2019.

21) The Company is also requesting an increase in its Balancing Charge, which recovers the cost of providing storage and peaking services, from the current charge of $0.090052 per therm (including losses and SUT) to a charge of $0.102825 per therm (including losses and SUT) which is supported in Attachment D. This charge is applicable only for the period November through March.

22) The Company is requesting a decrease in its Storage Inventory Carrying Charge which is shown on page 2 of Attachment D and is recovered through the balancing and commodity charges. The requested charge is $0.004352 per therm (excl. losses & SUT) for the balancing portion and $0.006323 per therm (excl. losses & SUT) for the commodity portion using the applicable sendout for each.

23) Price levels in the natural gas market have decreased from the levels in effect last year at this time. As illustrated on Item 8 herein, the NYMEX price for June 2018 is 14.5% lower this year as compared to last year, and the average monthly price for the entire forecasted period is 14.8% lower this year as compared to last year. The May 10, 2018 forward NYMEX strip used by the Company in this filing shows that prices are expected to rise modestly from current levels through the first quarter of 2019, followed by a reduction for the balance of the BGSS period. One of the primary drivers for this decrease in prices compared to last year's levels is the record natural gas production witnessed over the past 6 months. In fact, an all-time production level of 79 Bcf/d was achieved just recently, accounting for much of the reason why prices have remained moderate despite national

storage levels 25% below the 5 year average. These lower anticipated commodity price levels based on the NYMEX strip has allowed the Company to propose the decrease in rates to the RSG customers.

24) The current NYMEX futures prices that the Company utilized to develop its filing, as shown on Item 8, are based on the NYMEX of May 10, 2018. A comparison of these prices with the prices included in our current BGSS rate (from last year's BGSS filing indicates an average decrease of approximately 14.8%.

25) In this filing the Company includes the following:

a. The Company estimates that a decrease in BGSS revenue of approximately $24.8 million (excluding losses and SUT) would be required for the period of October 1, 2018 through September 30, 2019;

b. The requested decrease for BGSS-RSG Commodity Service is from the current charge of $0.368938 per therm (including losses and SUT) to a charge of $0.349579 per therm (including losses and SUT).

c. The requested increase in its Balancing Charge from the current charge of $0.090052 per therm (including losses and SUT) to a charge of $0.102825 per therm (including losses and SUT)

26) Residential annual bills comparing the current and proposed BGSS charge and the Balancing Charge, pursuant to this filing are included in the attached form of public notice attached hereto as Attachment C. The impact of the requested BGSS-RSG Charge and Balancing Charge changes for a typical residential gas heating customer using 165 therms per month during the winter months and 1,010 therms on an annual basis is a decrease in the

winter monthly bill of approximately 1.0%; and, on an annual basis the impact is also a decrease of approximately 1.3%. Moreover, pursuant to paragraph 10 of the above-referenced January 6, 2003 Order Approving Price Structure the attached Notice also indicates that such proposed rates may be subject to self-implementing rate increases of up to 5% on the ensuing December 1st and February 1st. The impact of such potential self-implementing increases on an average residential bill (1,200 therms annually) is an increase of approximately $10.39 for a winter month on December 1, 2018 and an additional approximate increase of $10.39 per winter month on February 1, 2019.

27) The proposed Tariff Sheet (redlined and non-redlined) to implement the above request have been attached hereto as Attachment B.

28) A form of notice and public hearing dates setting forth the request for an increase in BGSS-RSG Commodity Charge will be placed in newspapers having a circulation within the Company's gas service territory, and notice of this filing will be served on the County Executives and Clerks of all municipalities within the Company's gas territory upon the receipt, scheduling and publication of hearing dates. A copy of the form of newspaper notice of this request is attached hereto as Attachment C.

29) For the period beginning on October 1, 2017 to the filing of this proceeding, the Company has not experienced any main breaks caused by third parties involving losses of natural gas valued at $50,000 or more.

CONCLUSION

WHEREFORE, Public Service hereby requests that the Board issue a written Order by October 1, 2018 decreasing the Company's BGSS-RSG Commodity Charge from the current charge of $0.368938 per therm (including losses and SUT) to a charge of $0.349579 per therm (including losses and SUT), increasing the Balancing Charge from $0.090052 per therm (including losses and SUT) to $0.102825 per therm (including losses and SUT) and, accordingly, modify the Tariff for Gas Service, B.P.U.N.J. No. 15 Gas, pursuant to N.J.S.A, 48:2-21 and 48:2-21.1.

Respectfully submitted,

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Original signed by
BY: Matthew W. Weissman, *Esq.*
Matthew W. Weissman, Esq.
General Regulatory Counsel - Rates
PSEG Services Corporation
80 Park Plaza, T5G
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DATED: June 1, 2018
Newark, New Jersey

STATE OF NEW JERSEY)
ss:
COUNTY OF ESSEX)

DAVID F. CAFFERY of full age, being duly sworn according to law, on his oath deposes and says:

1. I am David F. Caffery for Public Service Energy Resources and Trade LLC who is filing this testimony on behalf of Public Service Electric and Gas Company.

2. I have read the annexed Motion and the matters contained therein, and they are true to the best of my knowledge and belief.

Original signed by David F. Caffery

DAVID F. CAFFERY

Sworn to and subscribed to
before me this 1st day of
June, 2018

Original signed by
Deborah S. Marks

DEBORAH S. MARKS
Notary Public
State of New Jersey
My Commission Expires June 3, 2023
ID# 2374254

ATTACHMENT A

TESTIMONY
OF
DAVID F. CAFFERY
VICE PRESIDENT – GAS SUPPLY

OVERVIEW

My qualifications are attached as Schedule DFC-1. This testimony supports Public Service Electric and Gas Company's (Public Service, the Company) Motion for a decrease in its Basic Gas Supply Service (BGSS) default Commodity Charge applicable to residential (RSG) customers and for an increase in its Balancing Charge applicable to rate schedules RSG, General Service (GSG), Large Volume Service (LVG), and Contract Service (CSG) where applicable. The requested decrease for BGSS-RSG Commodity Service is from the current charge of $0.368938 per therm (including losses and New Jersey Sales and Use Tax, SUT) to a charge of $0.349579 per therm (including losses and SUT). The requested increase for the Balancing Charge is from the current charge of $0.090052 per therm (including losses and New Jersey Sales and Use Tax, SUT) to a charge of $0.102825 per therm (including losses and SUT). These charges are requested to be effective by October 1, 2018, or earlier should the Board deem it appropriate, and would remain in effect until the earlier of September 30, 2019 or the effective date of the Company's next periodic BGSS Commodity Charge filing, subject to the potential self-implementing increases discussed in the Company's Motion. The revenue impact of the BGSS reduction is approximately $24.8 million (excluding SUT). Also provided in Attachment D are schedules that support the proposed changes to the Balancing Charge and Storage Inventory Carrying Charge. The combined annual bill impact of the proposed changes is a decrease of approximately 1.3% on a typical residential gas heating customer using 165 therms per month during the winter months and 1,010 therms annually.

The RSG customer class is expected to be under recovered by $21.0 million by September 30, 2018. This period began with an over recovery of $0.9 million (including the interest rollover). The primary reason for the decrease in the over recovery balance during this period are the Bill Credits provided to residential customers during the months of January to April 2018.

The filing herein complies with the provisions of the Annual BGSS Minimum Filing Requirements (comprised of 17 items) in Docket No. GR02090702, approved by the Board on June 20, 2003 (Minimum Filing Requirements Settlement). Since Item 1 is the Company's Motion, Testimony and Tariff Sheets, Items 2 through 17 are discussed below.

As part of the settlement of the 2015-2016 BGSS proceeding the Parties agreed to the following: Beginning with the 2016-2017 BGSS period, the Company agrees to prepare a Gas Supply Plan with details concerning the Company's objectives, approach, and plans for supplying gas to its residential customers. The Gas Supply Plan (Item 18) will include the following elements:

- *Gas Procurement Objectives*
- *Current and Forecasted Gas Service Requirements*
- *Projected Sources of Capacity*
- *Affiliate Relationships/Asset Management*
- *Hedging Plan and Strategy*
- *Capacity Releases/Off-System Sales*

More recently, as part of the settlement of the 2016-2017 BGSS proceeding the Parties agreed to the following: PSE&G agrees that as part of providing the forgoing, in its 2017-2018 and subsequent BGSS filings, it will provide specific information regarding changes to the

Company's pipeline transportation and storage capacity portfolio that are planned or under construction that could impact the costs to be included in the annual BGSS filings. If information to be provided pursuant to the forgoing requires confidential treatment, PSE&G will withhold such information until an agreement of non-disclosure is in place. In addition, as part of the settlement of the 2017-2018 BGSS proceeding, the Parties agreed that: MFR Item No. 18 (Gas Supply Plan) shall include a listing of all existing pipeline and storage capacity contracts for which the Company has given notice to extend or terminate during the previous 12 months, and all contracts that were extended under evergreen provisions during the same period. Since the filing already contains Annual BGSS Minimum Filing Requirements consisting of 17 items, we have included this new requirement as Item 18.

2. <u>Computation of Proposed BGSS Rates</u>

This summary schedule shows the forecasted BGSS cost components and applicable credits that comprise the basis for the proposed BGSS rate that is to become effective October 1, 2018. Additional details on the cost components and applicable credits are provided in several of the other items, as specified in the Minimum Filing Requirements Settlement. This schedule computes the BGSS Commodity Charge to residential gas customers based on all the forecasted gas cost components and applicable credits using forecasted sendout. Also included is an adjustment for the prior period under recovery, which is the result of a comparison of actual revenue recovered to actual cost (including applicable credits). Interest for the period is negative, therefore zero has been included.

Price levels in the natural gas market have decreased from the levels in effect last year at this time. As illustrated on Item 8 herein, the NYMEX price for June 2018 is

14.5% lower this year as compared to last year, and the average monthly price for the entire forecasted period is 14.8% lower this year as compared to last year. The May 10, 2018 forward NYMEX strip used by the Company in this filing shows that prices are expected to rise modestly from current levels through the first quarter of 2019, followed by a reduction for the balance of the BGSS period. One of the primary drivers for this decrease in prices compared to last year's levels is the record natural gas production witnessed over the past 6 months. In fact, an all-time production level of 79 Bcf/d was achieved just recently, accounting for much of the reason why prices have remained moderate despite national storage levels 25% below the 5 year average. These lower anticipated commodity price levels based on the NYMEX strip has allowed the Company to propose the decrease in rates to the RSG customers.

3. Public Notice with Proposed Impact on Bills

Included as Attachment C is a copy of the Company's Public Notice with details concerning the impact of the proposed BGSS-RSG rate on typical residential gas bills at various winter therm utilization levels. The Notice includes a table showing the impacts at various levels and also a reference to the possibility of self-implementing BGSS Commodity increases of 5% on December 1, 2018 and February 1, 2019, respectively, with the impact of those possible increases.

4. Actual and Forecasted Refund Amounts

The first schedule of Item 4 shows actual supplier refunds, totaling approximately $97 thousand, that were credited to BGSS-RSG recovery costs from May 2017 through the date of this filing and the second schedule shows that there are no estimated supplier refunds (in excess of $1 million) through September 2019. These two schedules are intended to show the actual and forecasted refunds that are received by the Company as the result of various FERC proceedings and returned to the residential customers through the BGSS Commodity Charge.

5. <u>Cost of Gas Sendout by Component</u>

This schedule includes monthly data showing the derivation of all cost components used to calculate the BGSS residential sendout for the projected period. The individual components are utilized to derive inventory values, which form the basis of the over/under collection for the period. All of the fixed and variable charges are allocated proportionately to the residential and commercial and industrial (C & I) customer groups monthly based on the estimated firm sendout and are trued up when the actual firm sendout is available. Each class of customers also shares equitably in any applicable credits or contributions that serve to lower gas costs, with the exception that contributions from CSG service provided to PSEG Power's New Jersey generation facilities are credited 100% to the Company's residential gas customers. The gas costs are similarly allocated to the respective customer classes following the direct allocation of any volumes hedged exclusively for the residential category.

6. <u>BGSS Contribution and Credit Offsets</u>

This schedule provides monthly data showing the derivation of all BGSS cost offsets, including interruptible margins, off-system sales & capacity release transactions, pipeline refunds and other credits. Included are the credits for each of the interruptible services, showing the actual credits, and the estimated credits as calculated pursuant to the

Board approved rate schedule, where applicable. These total contribution amounts serve as a credit against the total gas costs for the residential customer and are used to set the initial BGSS rate. The actual contributions are calculated monthly and, along with the actual gas costs incurred, are compared to the revenues collected and are reflected in the over/under recovery amounts for the customers as noted in Item 7 below.

7. <u>Over/Under Recovery Comparisons</u>

The schedules under this Item provide the derivation of the monthly over or under recoveries plus cumulative balances for the reconciliation and projected period. For the reconciliation period, one schedule also shows the calculation of the monthly actual or estimated accrued interest. The net interest calculated during the October 2017 to September 2018 period is negative and therefore has not been included in the calculation of the new BGSS charge on Item 2. There are two schedules that include data shown for the projected period: One showing the projected over/(under) recovery based on the current BGSS rate. The second is based on the filed BGSS rate that is necessary to achieve a zero balance at September 2019. Also included are supporting workpapers for the reconciliation period.

8. <u>Wholesale Gas Pricing Assumptions</u>

This schedule details the monthly gas prices for the end of the reconciliation period through September 2018 and the projected period through September 2019 along with a comparison of these prices with the prices included in the current BGSS rate (from last year's BGSS filing) which indicates an decrease of approximately 14.8%. These estimates reflect the future NYMEX prices on May 10, 2018, when this analysis was done.

9. GCUA Recoveries and Balances

This schedule is no longer necessary since the Gas Cost Underrecovery Adjustment (GCUA) recovery has been completed.

10. Historical Service Interruptions

This schedule provides the details of all service interruptions during the past 12 months. Included are all of the interruptible transportation and sales services, as well as the date and duration of the interruption and the number of customers affected.

11. Gas Price Hedging Activities

Included in this Item are the Company's last four quarterly hedging reports as filed with the Board. The reports provide gas purchase volume requirements and price-hedged volumes broken down into the Non-Discretionary Method and the Dollar Budget Method. As agreed to in the Settlement of the 2009/2010 BGSS proceeding, the Company has revised the Quarterly Hedging Report beginning with the June 30, 2010 report. The revised report provides more detail, including data on targets and a comparison of the two hedging methods.

The Company continues to utilize hedging as a means to stabilize the price of gas to the residential customer. The consistent goal of the program is to assure a reasonable level of price stability, not necessarily achieving the lowest possible price. The Company, to date, has locked in prices for approximately 99% of its planned volume for the 2018 summer period and approximately 69% of its planned volume for the 2018-2019 winter period and approximately 38% of its planned volume for the 2019 summer period. Hedging for the winter 2019-2020 period has just begun in May. The goal of the Company's hedging activities is to achieve a stable price through a disciplined hedging strategy that will, in the long run, result in a competitive price for the customer.

12. Storage Gas Volumes, Prices and Utilization

This schedule provides the Company's monthly data for LNG, LPG, and pipeline storage volumes. For the LNG and LPG, the schedules show volumes and dollars for balances at the various locations where the product is stored. The attached schedule for storage activity shows the ending balances for each storage service the Company has under contract. The Company does not value storage services individually, but treats them collectively as a total inventory.

13. Affiliate Gas Supply Transactions

As agreed to in the Settlement of the 2017/18 BGSS proceeding Item 13 now outlines all the principal terms of the Gas Requirements Contract between PSE&G and PSEG ER&T which provides BGSS services for all of PSE&G's gas customers.

14. Supply and Demand Data

Included in this schedule is the Company's Supply/Demand data that shows the Company's firm requirements and gas supplies by component on an annual, heating season and non-heating season basis.

15. Actual Peak Day Supply and Demand

Included in this schedule is the data for the five highest demand days, for each of the last three years, showing the date, the temperature, firm and interruptible volumes and the sources of supply used to meet the associated volume requirement.

16. Capacity Contract Changes

Included in this schedule is the most recent peak day forecast and the supplies to be utilized to meet these requirements. Included are the details for the current winter season concerning any changes to interstate pipeline contracts (entitlements, storage capacities, daily deliverability, or transportation) and the forecast for the next four (4) winter seasons. Also, as agreed to in the Settlement of the 2009/2010 BGSS proceeding, the Company has included extensive details on the forecast and forecasting process.

17. FERC Pipeline Activities

The attached schedule includes details on pending FERC dockets that would affect the cost of services received from the Company's interstate pipelines. The Company has also provided details concerning its participation in such dockets and included a listing of any filings or testimony made by or on behalf of the Company.

18. Gas Supply Plan

As discussed earlier herein, Item 18 consists of an overview of the Company's Gas Supply Plan which provides additional information as to the Company's procurement activities, supply planning, forecasted requirements, hedging activities and capacity release and off-system sales.

OTHER CHARGES

Attachment D includes the supporting information for a change in the Balancing Charge, which is comprised of three components: Annual Allocated Costs for storage and peaking supplies (page 1), Storage Inventory Carrying Charge (page 2), and Revenue Requirement on Production Plants (page 3).

The Balancing Charge is applicable to rate schedules RSG, GSG, LVG, and CSG where applicable and recovers the cost of providing storage and peaking services. The requested increase is from the current Balancing Charge of $0.090052 cents per balancing therm (including losses and SUT) to a Balancing Charge of $0.102825 cents per balancing therm (including losses and SUT). Attachment D provides the detail and support for this change, which is summarized on the bottom of page 1. The Balancing Charge is applicable only for the period November through March.

The base Balancing Charge includes the annual allocated cost for transportation, storage and peaking supplies used by the Company to meet the requirements of its customers. The requested charge is $0.087480 cents per balancing therm (excluding losses and SUT), which is an increase from the previous charge of $0.076447 cents per balancing therm (excluding losses and SUT). The increase is the result of the projected increased costs associated with the Transco rate case that Transco is required by the FERC to file on August 31, 2018.

The Storage Inventory Carrying Charge is shown on page 2 and is recovered in the balancing and commodity charges. The requested charge is $0.004352 cents per balancing therm (excl. losses & SUT) for the balancing portion and $0.006323 cents per therm (excl. losses & SUT) for the commodity portion (included in Item 2) using the applicable sendout for each. This is a decrease from the previous charge of $0.004680 cents per balancing therm for Balancing and $0.006945 cents per therm for Commodity (excluding losses and SUT).

The Revenue Requirement on Production Plant is shown on page 3 and the requested charge is $0.002675 cents per therm (excl. losses & SUT), which is a decrease from the previous charge of $0.002910 cents per therm (excluding losses and SUT).

Also included in Attachment D is a decrease in the A&G charge. This change is included in Item 2. The current rate is $0.04030 per dth and the updated rate is $0.03698 per dth. This rate recovers the administrative cost associated with PSEG Energy Resources & Trade's provision of gas supply services to PSE&G.

CONCLUSION

The Company's filing should be approved as reasonable and fully supported. The Company stands ready to respond to any reasonable requests for additional data. The Company seeks a Board Order by October 1, 2018 or earlier, should the Board deem it appropriate, implementing the proposed BGSS Commodity Charge decrease and approving the proposed increase in its Balancing Charge.

PROFESSIONAL QUALIFICATIONS
OF
DAVID F. CAFFERY
<u>VICE PRESIDENT – GAS SUPPLY</u>

My name is David F. Caffery and my business address is 80 Park Plaza, Newark, New Jersey 07102-0570. I am the Vice President – Gas Supply for PSEG Energy Resources and Trade LLC (PSEG-ERT).

In May 1977, I graduated from Lafayette College with a Bachelor of Science degree in Civil Engineering. In 1982, I received a Master of Business Administration degree in Finance from Fairleigh Dickinson University. I began my employment with Public Service Electric and Gas Company in July 1977 as an Associate Engineer in the Fuel Supply Department. During the period from 1977 through 1998 I received a series of promotions to the level of Manager - Gas Supply in April 1998. In June 2002, as a result of the transfer of the gas supply contracts, I became an employee of PSEG-ERT. I was promoted to Director – Portfolio Management & Regulatory in March 2007. I assumed my present position in March 2017. In my present position I am responsible for all aspects of the BGSS and Fuels activities conducted by PSEG-ERT.

I am a member of the American Gas Association, having served as past Chairman of its Federal Regulatory Committee during 2016. I have provided testimony before the Federal Energy Regulatory Commission and the New Jersey Board of Public Utilities.

2. <u>Computation of Proposed BGSS Rates</u>

Item 2

COMPUTATION OF
BGSS COMMODITY CHARGE FOR RSG
OCTOBER 2018 - SEPTEMBER 2019

($-000)

	12-MONTH LEVELIZED	
	$000	**$/DTh**
FIXED COSTS:		
FT DEMAND COST	$ 148,598	$1.0249
STORAGE DEMAND/CAPACITY COSTS	72,492	0.5000
STORAGE INJ & W/D COSTS	5,017	0.0346
PEAKING COSTS	8,954	0.0618
	235,060	**$1.6212**
CONTRIBUTIONS	(29,789)	(0.2055)
PIPELINE REFUNDS		0.0000
OFF-SYSTEM SALES MARGIN	(39,014)	(0.2691)
ELECTRIC CONTIBUTION - CSG	(15,886)	(0.1096)
NET TOTAL FIXED COST	**$ 150,370**	**$1.03710**
FIRM RSG SENDOUT (MDTh) 10/18 - 9/19	**144,988**	
TOTAL NON-GULF COAST COST ($/DTh)		**$1.03710**
Removal of Balancing Cost (incl. above)		(0.57183)
Inventory Carrying Charge Allocation		0.06323
Gas Supply A&G		0.03698
Total Adjustments		**($0.47162)**
ADJUSTED NON-GULF COAST COST ($/DTh)		**$0.56548**
(OVER)/UNDER RECOVERY @ 9/30/18 - INCL. INTEREST	**$ 21,000**	**$0.14480**
GULF COAST COST OF GAS ($/DTh)		
FT COMMODITY AND FUEL		0.00000
COST OF GAS		**2.50273**
TOTAL GULF COAST COST		**$2.50273**

SUMMARY OF CHARGE COMPONENTS

	(cents/therm) BGSS-RSG	(dollars/therm) BGSS-RSG
Estimated Non-Gulf Coast Cost of Gas	5.6548	$ 0.056548
Capital Adjustment Charge (CAC)	-	$ -
Adjusted Non Gulf Coast Cost of Gas	5.6548	$ 0.056548
Estimated Gulf Coast Cost of Gas	25.0273	$ 0.250273
Adjustment to Gulf Coast Cost of Gas	-	$ -
Prior Period (Over)/Under Recovery	1.4480	$ 0.014480
Adjusted Cost of Gas	32.1301	$ 0.321301
COMMODITY CHARGE (after application of losses 2.0%)	**32.7858**	**$ 0.327858**
COMMODITY CHARGE (including SUT)	**34.9579**	**$ 0.349579**

3. Public Notice with Proposed Impact on Bills

Notice (including Typical Bills) – Attachment C

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY GAS CUSTOMERS

IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S 2018/2019 ANNUAL BGSS COMMODITY CHARGE FILING FOR ITS RESIDENTIAL GAS CUSTOMERS UNDER ITS PERIODIC PRICING MECHANISM AND FOR CHANGES IN ITS BALANCING CHARGE

Notice of Filing
And
Notice of Public Hearings

Docket No. XXXXXXXXXX

TAKE NOTICE that, on June 1, 2018, Public Service Electric and Gas Company ("Public Service", "the Company") filed a Motion and supporting testimony (Annual BGSS Commodity Charge filing) with the New Jersey Board of Public Utilities ("Board", "BPU") requesting that the Board permit Public Service to decrease its Basic Gas Supply Service (BGSS-RSG) Commodity Charge to Residential Service (RSG) customers and to increase its Balancing Charge to customers receiving service under RSG, General Service (GSG), Large Volume Service (LVG) and Contract Service (CSG) where applicable effective October 1, 2018, or earlier, should the Board deem it appropriate. Approval of the Company's request would result in a decrease in annual BGSS-RSG revenues of approximately $24.8 million (excluding losses and New Jersey Sales and Use Tax, SUT). The requested decrease in the BGSS-RSG Commodity Charge is from $0.368938 per therm (including losses and SUT) to $0.349579 per therm (including losses and SUT). The requested increase in the Balancing Charge is from $0.090052 per therm (including SUT) to $0.102825 per therm (including SUT).

Based on rates effective June 1, 2018, the combined effect of the requested decrease in the annual BGSS Commodity Charge and increase in the Balancing Charge on typical residential gas bills, if approved by the Board, is shown in Table #1.

Under the Company's proposal, a residential heating customer using 100 therms per month during the winter months and 610 therms on an annual basis would see a decrease in the annual bill from $558.56 to $551.49, or $7.07 approximately 1.3%. Moreover, under the Company's proposal, a typical residential heating customer using 165 therms per month during the winter months and 1,010 therms on an annual basis would see a decrease in the annual bill from $879.16 to $867.45, or $11.71 approximately 1.3%.

In addition, the Board, in its Order in Docket No. GX01050304 dated January 6, 2003, granted Public Service approval to increase its Commodity Charge rates to be effective December 1st of this year and/or February 1st of next year on a self-implementing basis, with each such increase being subject to a maximum rate increase of 5% of the average rate based on a typical 100 therms per month average (1,198 therms annual usage) residential customer's total bill. Such rate increases shall be preconditioned upon written notice by Public Service to the BPU Staff and to the Division of Rate Counsel no later than November 1st of this year and/or January 1st of next year of its intention to apply a December 1st or a February 1st self-implementing rate increase, respectively, and the approximate amount of the increases based upon then current market data. These increases, if implemented, would be in accordance with the Board approved methodology.
Should it become necessary to apply the December 1st self-implementing 5% increase, the bill impact would be an increase as illustrated in Table #2. Further, if a February 1st self-implementing 5% increase becomes necessary, then there would be an additional increase as also shown in Table #2.

The above requests will not result in any profit to the Company.

Any final rate adjustments with resulting changes in bill impacts found by the Board to be just and reasonable as the result of this filing may be modified and/or allocated by the Board in accordance with the provisions of N.J.S.A. 48:2-21, and for other good and legally sufficient reasons, to any class or classes of customers of the Company. Therefore, the above described charges may increase or decrease based upon the Board's decision.

Copies of the Company's Motion and its supporting documents can be reviewed at the Company's Customer Service Centers, online at the PSEG Web site at http://www.pseg.com/pseandgfilings and at the Board of Public Utilities at 44 South Clinton Avenue, Seventh Floor, Trenton, New Jersey 08625-0350.The following dates, times and locations for public hearings have been scheduled on the Company's filing so that members of the public may present their views.

Date 1, 2018	Date 2, 2018	Date 3, 2018
Time 1	Time 2	Time 3
Location 1	Location 2	Location 3
Location 1 Overflow	Location 2 Overflow	Location 3 Overflow
Room 1	Room 2	Room 3
Room 1 Overflow	Room 2 Overflow	Room 3 Overflow
Address 1	Address 1	Address 1
City 1, New Jersey Zip 1	City 2, New Jersey Zip 2	City 3, New Jersey Zip 3

In order to encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, including interpreters, listening devices or mobility assistance, 48 hours prior to the above hearings.

Customers may file written comments with the Secretary of the Board of Public Utilities at 44 South Clinton Avenue, Third Floor, Suite 314, P.O. Box 350, Trenton, New Jersey 08625-0350 ATTN: Secretary Aida Camacho-Welch whether or not they attend the public hearings. To review PSE&G's rate filing, visit http://www.pseg.com/pseandgfilings.

Table # 1
Residential Gas Service

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Then Your Present Monthly Winter Bill (1) Would Be:	And Your Proposed Monthly Winter Bill (2) Would Be:	Your Monthly Winter Bill Change Would Be:	And Your Monthly Percent Change Would Be:
180	25	$26.06	$25.80	($0.26)	(1.00)%
360	50	46.30	45.77	(0.53)	(1.14)
610	100	88.48	87.61	(0.87)	(0.98)
1,010	165	142.23	140.79	(1.44)	(1.01)
1,198	196	167.90	166.19	(1.71)	(1.02)
1,224	200	171.18	169.43	(1.75)	(1.02)
1,836	300	253.84	251.21	(2.63)	(1.04)

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) in effect June 1, 2018, and assumes that the customer receives commodity service from Public Service.

(2) Same as (1) except includes the proposed change in BGSS-RSG and Balancing Charge.

Table # 2
Residential Gas Service

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Self-Implementing 5% Increases	
		December 1, 2018 Monthly Winter Change Would Be:	February 1, 2019 Monthly Winter Change Would Be:
180	25	$1.28	$1.28
360	50	2.56	2.56
610	100	5.30	5.30
1,010	165	8.75	8.75
1,198	196	10.39	10.39
1,224	200	10.60	10.60
1,836	300	15.91	15.90

Matthew M. Weissman
General Regulatory Counsel - Rates

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

4. Actual and Forecasted Refund Amounts

Item 4

NATURAL GAS PIPELINE REFUNDS RECEIVED

(000)

MONTH	SUPPLIER	AMOUNT	TOTAL
May	Transco	8	8
June	Columbia	18	
	Texas Eastern	71	89
Total			97

Item 4

PENDING FERC CASES WHICH CONTAIN SOME POSSIBILITY OF REFUNDS TO PSE&G IN EXCESS OF $1 MILLION

(000)

DOCKET	SUPPLIER	STATUS

NO REFUNDS

5. Cost of Gas Sendout by Component

ACTUAL COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Total
Beginning Inventory Price $000	$194,120	$208,379	$198,022	$165,890	$139,580	$112,943	$72,000	
Fixed Pipeline Charge $000	$17,221	$18,285	$18,605	$18,203	$17,272	$17,754	$16,935	
Gas Purchases and Hedges $000	$15,726	$31,248	$47,202	$68,693	$30,228	$28,055	$27,294	
Receipt Value $000	$32,948	$49,533	$65,807	$86,896	$47,500	$45,809	$44,229	$372,723
Total Inventory Value $000	$227,068	$257,912	$263,829	$252,786	$187,081	$158,752	$116,229	
Total $/dth	$3.70	$3.74	$3.68	$3.83	$3.88	$3.99	$3.84	
Beginning Inventory Volume MDth	51,042	56,264	52,966	45,124	36,416	29,089	18,035	
Receipt Volume MDth	10,261	12,738	18,660	20,801	11,763	10,719	12,265	97,208
Total Inventory Volume MDth	61,304	69,002	71,626	65,925	48,179	39,808	30,301	
RSG Sendout MDth	5,052	16,003	26,698	29,547	19,097	21,727	13,729	131,852
Total RSG Sendout Cost $000	$18,712	$59,813	$98,339	$113,296	$74,154	$86,645	$52,664	$503,624
Ending Inventory Rebalance								
Volume	12	(33)	196	38	7	(46)	125	
Amount	$23	($77)	$400	$91	$17	($107)	$289	

FORECASTED COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Total Oct - Sept
Beginning Inventory Cost $000	$63,854	$90,593	$118,813	$149,387	$172,009	$199,313	$216,722	$223,257	$191,554	$135,715	$89,925	$59,578	$63,960	$88,670	$116,510	$146,094	$175,917	
Receipt Value $000	$45,927	$42,851	$41,808	$33,943	$39,189	$44,501	$69,246	$65,519	$56,607	$54,071	$51,104	$46,562	$47,009	$44,359	$41,667	$41,514	$39,144	$601,303
Total Inventory Value $000	$109,781	$133,444	$160,621	$183,330	$211,199	$243,815	$285,967	$288,776	$248,161	$189,785	$141,029	$106,140	$110,969	$133,029	$158,177	$187,608	$215,061	
Total $/dth	$3.55	$3.78	$3.92	$4.08	$4.15	$4.18	$4.13	$4.12	$4.14	$4.14	$4.07	$4.07	$4.09	$4.12	$4.17	$4.21	$4.25	
Beginning Inventory Volume MDth	16,696	25,489	31,459	38,136	42,143	48,031	51,826	54,087	46,522	32,818	21,698	14,633	15,711	21,700	28,271	34,997	41,829	
Receipt Volume MDth	14,191	9,844	9,545	6,781	8,752	10,274	17,454	16,047	13,487	12,975	12,941	11,439	11,446	10,579	9,621	9,612	8,792	144,667
Total Inventory Volume MDth	30,888	35,333	41,004	44,917	50,896	58,305	69,280	70,135	60,009	45,793	34,639	26,073	27,158	32,280	37,892	44,609	50,621	
RSG Sendout MDth	5,399	3,874	2,868	2,774	2,864	6,479	15,192	23,612	27,191	24,095	20,006	10,361	5,457	4,008	2,895	2,780	2,911	144,988
Total RSG Sendout Cost $000	$19,188	$14,631	$11,234	$11,320	$11,885	$27,093	$62,710	$97,222	$112,446	$99,860	$81,451	$42,180	$22,299	$16,519	$12,083	$11,691	$12,365	$597,921

6. BGSS Contribution and Credit Offsets

Actual BGSS Contribution and Credit Offsets

($000)

			Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Total
(1)	**BGSS-I Contribution**		$104	$130	$74	$47	$1,869	$131	($878)	$1,479
(2)	**Cogeneration Contribution**		$656	$198	$376	($49)	$3,135	$1,082	$823	$6,219
(3)	**TSG-F Contribution**		$143	($27)	$429	$345	$253	$301	$487	$1,930
(4)	**"Contribution"**	Sum of (1) through (3)	$903	$301	$879	$342	$5,257	$1,514	$432	$9,628
(5)	**Off-System Contribution**		$6,698	$4,642	$12,278	$27,105	$8,796	$4,152	$3,440	$67,111
(6)	**Electric Contribution**		$1,271	$530	$1,010	$970	$704	$871	$1,265	$6,621
(7)	**FT-S Balancing Credit**		$1	$2,089	$425	$4,900	$3,456	$2,313	$686	$13,869
(8)	**Pipeline Refunds**		$0	$0	$0	$0	$0	$0	$0	$0

Forecasted BGSS Contribution and Credit Offsets

		May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Total Oct - Sept
(1)	**BGSS-RSG Sendout, Mdth**	5,622	3,874	2,868	2,774	2,864	6,479	15,192	23,612	27,191	24,095	20,006	10,361	5,457	4,008	2,895	2,780	2,911	144,988
(2)	**BGSS-F Sendout, Mdth**	1,701	1,401	1,070	1,035	1,168	2,184	4,091	7,081	9,700	8,935	7,438	3,219	1,635	1,419	1,070	1,028	1,178	48,977
(3)	**Total Firm Sendout, Mdth**	7,323	5,274	3,938	3,808	4,032	8,663	19,283	30,693	36,892	33,030	27,443	13,581	7,092	5,428	3,965	3,808	4,088	193,965
(4)	**Annual % BGSS-RSG of Firm Sendout**	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%
(5)	**BGSS-I Contribution**	$41.6	$39.1	$33.3	$79.5	$62.8	$104.4	$123.4	$72.2	$47.6	$1,915.5	$134.7	($860.3)	$41.5	$38.9	$33.2	$79.4	$62.7	$1,793.1
(6)	**Cogeneration Contribution, $000**	$242.1	$281.8	$526.9	$439.7	$507.3	$719.3	$312.7	$383.2	($29.7)	$601.9	$602.3	$575.5	$241.5	$280.3	$525.6	$438.7	$506.1	$5,157.5
(7)	**TSG-F Contribution**	($66.6)	$140.0	$92.2	$87.2	$63.0	$143.3	($25.9)	$416.6	$349.4	$259.4	$308.7	$476.9	($66.4)	$139.3	$92.0	$87.0	$62.9	$2,243.1
(8)	**CSG**	$325.5	$325.5	$325.5	$325.5	$325.5	$325.5	$325.5	$325.5	$325.5	$325.5	$325.5	$325.5	$325.5	$325.5	$325.5	$325.5	$325.5	$3,905.7
(9)	**"Contribution"**	$542.6	$786.4	$977.9	$931.9	$958.5	$1,292.5	$735.7	$1,197.5	$692.8	$3,102.3	$1,371.2	$517.6	$542.1	$783.8	$976.2	$930.6	$957.1	$13,099.4
(10)	**Off-System Contribution, $000**	$1,032.5	$1,003.5	$1,032.5	$1,032.5	$1,003.5	$1,011.9	$7,093.0	$7,093.0	$5,326.1	$5,326.1	$7,093.0	$1,011.9	$1,011.9	$1,011.9	$1,011.9	$1,011.9	$1,011.9	$39,014.5
(11)	**Electric Contribution, $000**	$1,293.6	$1,489.2	$1,923.4	$1,595.1	$1,449.9	$1,215.3	$1,122.2	$1,167.0	$1,221.3	$1,194.7	$1,129.8	$1,084.3	$1,293.6	$1,489.2	$1,923.4	$1,595.1	$1,449.9	$15,885.8
(12)	**Pipeline Refund, $000**	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
(13)	**FT-S Balancing Use, Mdth**	0.0	0.0	0.0	0.0	0.0	0.0	3,231.1	5,311.8	5,589.7	6,066.0	5,324.2	0.0	0.0	0.0	0.0	0.0	0.0	
(14)	**Balancing Charge, $/dth**	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.8748	$0.8748	$0.8748	$0.8748	$0.8748	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
(15)	**FT-S Balancing Credit, $000**	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2,112.9	$3,473.4	$3,655.2	$3,966.6	$3,481.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$16,689.7
(16)	**BGSS-RSG Balancing Use, Mdth**	0	0	0	0	0	0	12,148	20,467	24,046	21,254	16,860	0	0	0	0	0	0	
(17)	**Balancing Charge, $/dth**	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.8748	$0.8748	$0.8748	$0.8748	$0.8748	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
(18)	**BGSS-RSG Balancing Rev., $000**	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$10,627.3	$17,904.2	$21,035.2	$18,593.1	$14,749.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$82,909.1

BGSS-RSG MARGIN FROM GAS TRANSPORTATION FOR ELECTRIC GENERATION

	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Total
BGSS Asset Charge ($000)	$879	$354	$717	$640	$529	$623	$889	$4,632
CSG Transportation Revenues ($000)	$392	$175	$293	$329	$175	$248	$376	$1,990
Total BGSS-RSG Margin ($000)	$1,271	$530	$1,010	$970	$704	$871	$1,265	$6,621

7. Over/Under Recovery Comparisons

Summary of Monthly Over/(Under) Recoveries

Calculation of Interest on Over/(Under) Balance

Over/(Under) Balance (before & after change)

Supporting Workpapers – Actual Results

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MONTHLY RECOVERIES COMPARED TO EXCESS COST
OCTOBER 2017 - SEPTEMBER 2018

(000)

		TOTAL RECOVERY	LESS: TOTAL EXPENSE	MONTHLY OVER/(UNDER) RECOVERY
Balance September 30, 2017				**$852**
Interest Adjustment				**71**
October 1, 2017 Adjusted Balance				**$923**
October 2017		$ 16,442	$ 13,141	3,301
November		62,015	57,555	4,460
December		111,441	90,409	21,032
January 2018		87,453	93,257	(5,804)
February		61,973	66,960	(4,987)
March		57,791	84,063	(26,272)
April		28,487	49,314	(20,827)
May	**(Est.)**	17,728	16,319	1,409
June	**(Est.)**	12,721	11,352	1,369
July	**(Est.)**	9,417	7,300	2,117
August	**(Est.)**	9,108	7,761	1,347
September	**(Est.)**	9,405	8,473	932
Total				**($21,000)**

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INTEREST
COMPUTED AT 8.21% ROR
OCTOBER 2017 - SEPTEMBER 2018

(000)

		OVER/(UNDER) RECOVERIES			
		Monthly	Cumulative	Average Balance	INTEREST
Balance September 30, 2017			**$852**		
Interest Adjustment			**71**		
October 1, 2017 Adjusted Balance			**$923**		
October 2017		$ 3,301	4,224	$ 2,574	$ 18
November		4,460	8,684	$ 6,454	44
December		21,032	29,716	19,200	131
January 2018		(5,804)	23,912	26,814	183
February		(4,987)	18,925	21,419	147
March		(26,272)	(7,347)	5,789	40
April		(20,827)	(28,174)	(17,761)	(122)
May	**(Est.)**	1,409	(26,765)	(27,470)	(188)
June	**(Est.)**	1,369	(25,396)	(26,081)	(178)
July	**(Est.)**	2,117	(23,279)	(24,338)	(167)
August	**(Est.)**	1,347	(21,932)	(22,606)	(155)
September	**(Est.)**	932	(21,000)	(21,466)	(147)
Total					**$ (394)**

BGSS-RSG 2018-2019
NYMEX====>>> May 10, 2018

NO CHANGE IN RATES

		BGSS-RSG MDTh	COST	REFUNDS	CONTRIB	OFF-SYS Margin	Electric Contribution	FT Balancing Credit	ADJ COST	RSG Bal. Revenue	BGSS RECOVERY	EXCESS COST	OVER/(UNDER) RECOVERY Month	Cumulative	RSG Rate $/dth
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(2).+.(7)	(9)	(10)=(1)*(14)+(9)	(11)=(10)-(8)	(12)=-(11)	(13)	(14)
Apr-18	**Act**													**($28,174)**	$3.2838
May-18	**Est.**	5,399	$19,188	$0	($543)	($1,032)	($1,294)	$0	$16,319	$0	$17,728	($1,409)	$1,409	($26,765)	$3.2838
Jun-18	**Est.**	3,874	$14,631	$0	($786)	($1,004)	($1,489)	$0	$11,352	$0	$12,721	($1,369)	$1,369	($25,396)	$3.2838
Jul-18	**Est.**	2,868	$11,234	$0	($978)	($1,032)	($1,923)	$0	$7,300	$0	$9,417	($2,117)	$2,117	($23,279)	$3.2838
Aug-18	**Est.**	2,774	$11,320	$0	($932)	($1,032)	($1,595)	$0	$7,761	$0	$9,108	($1,347)	$1,347	($21,932)	$3.2838
Sep-18	**Est.**	**2,864**	**$11,885**	**$0**	**($959)**	**($1,004)**	**($1,450)**	**$0**	**$8,474**	**$0**	**$9,405**	**($932)**	**$932**	**($21,000)**	$3.2838
Oct-18	**Est.**	6,479	$27,093	$0	($1,292)	($1,012)	($1,215)	$0	$23,574	$0	$21,276	$2,298	($2,298)	($23,298)	$3.2838
Nov-18	**Est.**	15,192	$62,710	$0	($736)	($7,093)	($1,122)	($2,113)	$51,646	$10,627	$60,516	($8,870)	$8,870	($14,428)	$3.2838
Dec-18	**Est.**	23,612	$97,222	$0	($1,197)	($7,093)	($1,167)	($3,473)	$84,291	$17,904	$95,442	($11,151)	$11,151	($3,277)	$3.2838
Jan-19	**Est.**	27,191	$112,446	$0	($693)	($5,326)	($1,221)	($3,655)	$101,550	$21,035	$110,326	($8,776)	$8,776	$5,499	$3.2838
Feb-19	**Est.**	24,095	$99,860	$0	($3,102)	($5,326)	($1,195)	($3,967)	$86,271	$18,593	$97,717	($11,446)	$11,446	$16,945	$3.2838
Mar-19	**Est.**	20,006	$81,451	$0	($1,371)	($7,093)	($1,130)	($3,482)	$68,376	$14,749	$80,444	($12,069)	$12,069	$29,014	$3.2838
Apr-19	**Est.**	10,361	$42,180	$0	($518)	($1,012)	($1,084)	$0	$39,567	$0	$34,025	$5,542	($5,542)	$23,472	$3.2838
May-19	**Est.**	5,457	$22,299	$0	($542)	($1,012)	($1,294)	$0	$19,451	$0	$17,921	$1,531	($1,531)	$21,941	$3.2838
Jun-19	**Est.**	4,008	$16,519	$0	($784)	($1,012)	($1,489)	$0	$13,234	$0	$13,163	$71	($71)	$21,870	$3.2838
Jul-19	**Est.**	2,895	$12,083	$0	($976)	($1,012)	($1,923)	$0	$8,172	$0	$9,505	($1,333)	$1,333	$23,203	$3.2838
Aug-19	**Est.**	2,780	$11,691	$0	($931)	($1,012)	($1,595)	$0	$8,153	$0	$9,128	($975)	$975	$24,178	$3.2838
Sep-19	**Est.**	**2,911**	**$12,365**	**$0**	**($957)**	**($1,012)**	**($1,450)**	**$0**	$8,946	**$0**	$9,558	($611)	$611	$24,789	$3.2838
Oct-17 to Sept-18		**144,988**	**$597,921**	**$0**	**($13,099)**	**($39,014)**	**($15,886)**	**($16,690)**	**$513,231**	**$82,909**	**$559,021**	**($45,789)**			

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BGSS-RSG 2018-2019
NYMEX====>>> May 10, 2018

ZERO BALANCE

	BGSS-RSG				OFF-SYS	Electric	FT Balancing		RSG Bal.	BGSS	EXCESS	OVER/(UNDER) RECOVERY		RSG Rate
	MDTh	COST	REFUNDS	CONTRIB	Margin	Contribution	Credit	ADJ COST	Revenue	RECOVERY	COST	Month	Cumulative	$/dth
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(2).+.(7)	(9)	(10)=(1)*(14)+(9)	(11)=(10)-(8)	(12)=-(11)	(13)	(14)
Apr-18 Act.													**($28,174)**	$3.2838
May-18 Est.	5,399	$19,188	$0	($543)	($1,032)	($1,294)	$0	$16,319	$0	$17,728	($1,409)	$1,409	($26,765)	$3.2838
Jun-18 Est.	3,874	$14,631	$0	($786)	($1,004)	($1,489)	$0	$11,352	$0	$12,721	($1,369)	$1,369	($25,396)	$3.2838
Jul-18 Est.	2,868	$11,234	$0	($978)	($1,032)	($1,923)	$0	$7,300	$0	$9,417	($2,117)	$2,117	($23,279)	$3.2838
Aug-18 Est.	2,774	$11,320	$0	($932)	($1,032)	($1,595)	$0	$7,761	$0	$9,108	($1,347)	$1,347	($21,932)	$3.2838
Sep-18 Est.	**2,864**	**$11,885**	**$0**	**($959)**	**($1,004)**	**($1,450)**	**$0**	**$8,474**	**$0**	**$9,405**	**($932)**	**$932**	**($21,000)**	$3.2838
Oct-18 Est.	6,479	$27,093	$0	($1,292)	($1,012)	($1,215)	$0	$23,574	$0	$20,168	$3,406	($3,406)	($24,405)	$3.1128
Nov-18 Est.	15,192	$62,710	$0	($736)	($7,093)	($1,122)	($2,113)	$51,646	$10,627	$57,919	($6,272)	$6,272	($18,133)	$3.1128
Dec-18 Est.	23,612	$97,222	$0	($1,197)	($7,093)	($1,167)	($3,473)	$84,291	$17,904	$91,405	($7,114)	$7,114	($11,019)	$3.1128
Jan-19 Est.	27,191	$112,446	$0	($693)	($5,326)	($1,221)	($3,655)	$101,550	$21,035	$105,677	($4,127)	$4,127	($6,893)	$3.1128
Feb-19 Est.	24,095	$99,860	$0	($3,102)	($5,326)	($1,195)	($3,967)	$86,271	$18,593	$93,597	($7,327)	$7,327	$434	$3.1128
Mar-19 Est.	20,006	$81,451	$0	($1,371)	($7,093)	($1,130)	($3,482)	$68,376	$14,749	$77,024	($8,648)	$8,648	$9,082	$3.1128
Apr-19 Est.	10,361	$42,180	$0	($518)	($1,012)	($1,084)	$0	$39,567	$0	$32,253	$7,314	($7,314)	$1,769	$3.1128
May-19 Est.	5,457	$22,299	$0	($542)	($1,012)	($1,294)	$0	$19,451	$0	$16,988	$2,464	($2,464)	($695)	$3.1128
Jun-19 Est.	4,008	$16,519	$0	($784)	($1,012)	($1,489)	$0	$13,234	$0	$12,477	$757	($757)	($1,452)	$3.1128
Jul-19 Est.	2,895	$12,083	$0	($976)	($1,012)	($1,923)	$0	$8,172	$0	$9,010	($839)	$839	($613)	$3.1128
Aug-19 Est.	2,780	$11,691	$0	($931)	($1,012)	($1,595)	$0	$8,153	$0	$8,653	($500)	$500	($114)	$3.1128
Sep-19 Est.	**2,911**	**$12,365**	**$0**	**($957)**	**($1,012)**	**($1,450)**	**$0**	**$8,946**	**$0**	**$9,060**	**($114)**	**$114**	**($0)**	$3.1128
Oct-17 to Sept-18	**144,988**	**$597,921**	**$0**	**($13,099)**	**($39,014)**	**($15,886)**	**($16,690)**	**$513,231**	**$82,909**	**$534,231**	**($21,000)**			

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PSE&G - BGSS For the Period Oct 17 to Sep18	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18
Beginning Balance	$ 922,840	$ 4,223,724	$ 8,684,082	$ 29,716,059	$ 23,911,753	$ 18,925,037	$ (7,346,919)
FUEL REVENUES							
Fuel Revenues	$ 15,538,287	$ 61,713,839	$ 110,562,290	$ 87,111,498	$ 56,715,582	$ 56,276,335	$ 28,055,725
Interruptible Contribution	$ 903,398	$ 300,681	$ 878,726	$ 341,981	$ 5,257,160	$ 1,514,236	$ 431,617
Total Fuel Revenues	$ 16,441,685	$ 62,014,520	$ 111,441,016	$ 87,453,480	$ 61,972,742	$ 57,790,571	$ 28,487,342
FUEL EXPENSE							
Gas Purchases	$ 13,140,801	$ 57,554,162	$ 90,409,039	$ 93,257,786	$ 66,959,459	$ 84,062,527	$ 49,314,396
Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Fuel Expense	$ 13,140,801	$ 57,554,162	$ 90,409,039	$ 93,257,786	$ 66,959,459	$ 84,062,527	$ 49,314,396
OVER / (UNDER) RECOVERY	$ 3,300,884	$ 4,460,359	$ 21,031,977	$ (5,804,306)	$ (4,986,716)	$ (26,271,956)	$ (20,827,054)
Cumulative Recovery	$ 4,223,724	$ 8,684,082	$ 29,716,059	$ 23,911,753	$ 18,925,037	$ (7,346,919)	$ (28,173,973)

BGSS
Calculation of Fuel Revenues

	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18
RSG Fuel Revenues	$ 15,297,471	$ 49,076,026	$ 85,884,990	$ 58,625,995	$ 38,317,322	$ 43,237,991	$ 26,668,180
RSGM Fuel Revenues	$ 295,303	$ 952,355	$ 1,735,144	$ 1,336,843	$ 844,573	$ 926,106	$ 641,689
Subtotal	$ 15,592,774	$ 50,028,381	$ 87,620,133	$ 59,962,838	$ 39,161,895	$ 44,164,097	$ 27,309,869
FT Balancing Revenues	$ (54,487)	$ 6,642,427	$ 17,481,523	$ 29,129,425	$ 20,469,780	$ 17,719,048	$ 745,856
FT Balancing Revenues (Unbilled Calc)	$ -	$ 5,043,032	$ 10,503,666	$ 8,522,901	$ 5,606,809	$ -	$ -
FT Balancing Revenues (Prior Unbilled Calc)	$ -	$ -	$ (5,043,032)	$ (10,503,666)	$ (8,522,901)	$ (5,606,809)	$ -
Total BGSSR Fuel Recovery	$ 15,538,287	$ 61,713,839	$ 110,562,290	$ 87,111,498	$ 56,715,582	$ 56,276,335	$ 28,055,725
Bill Credits							
Billed Revenues	$ 20,726	$ 10,013	$ (238,775)	$ (25,769,632)	$ (32,063,951)	$ (28,631,813)	$ (24,601,660)
Current Unbilled Usage	0	0	0	96,604,494	64,379,657	79,953,529	42,719,496
Prior Unbilled Usage	0	0	0	0	96,604,494	64,379,657	79,953,529
Net Unbilled Usage	0	0	0	96,604,494	-32,224,837	15,573,872	-37,234,033
Rate (.28 less 7% taxes)	($0.070175)	($0.070175)	($0.070175)	($0.140680)	($0.140680)	($0.140680)	($0.140680)
Subtotal Unbilled Revenues	$0	$0	$0	($13,590,320)	$4,533,390	($2,190,932)	$5,238,084
Total Bill Credits	$ 20,726	$ 10,013	$ (238,775)	$ (39,359,952)	$ (27,530,561)	$ (30,822,745)	$ (19,363,576)

Input Page

	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18
Interruptible Contributions:							
ISG (BGSS-I):							
ISG (BGSS-I) Sales Therms	363,394	646,027	757,914	1,385,058	1,467,880	1,158,206	1,251,387
ISG BGSS-I) Gross Revenues	$168,339	$292,320	$365,974	$714,323	$2,864,958	$540,585	-$678,086
ISG (BGSS-I) Cost	$36,897	$134,490	$239,253	$637,940	$382,376	$344,552	$164,498
PSEG Power's share of Contribution	$26,979	$27,738	$52,386	$29,428	$613,195	$64,663	$35,478
ISG Interuptible Contribution to BGSSR	$104,463	$130,092	$74,335	$46,954	$1,869,387	$131,370	($878,061)
CIG:							
CIG SBC Rate adjustment (line 84)							
CIG Sales Therms	3,368,651	3,280,611	4,186,464	3,500,544	3,477,394	3,868,616	5,389,866
CIG Gross Revenues	$1,443,822	$1,346,325	$1,812,703	$1,460,817	$4,152,569	$2,538,424	$1,573,425
CIG SBC/GPRC Revenues	$160,206	$156,019	$199,100	$166,479	$165,378	$183,984	$254,854
CIG Cost	$357,794	$738,961	$1,075,613	$1,331,214	$928,727	$1,060,921	$650,501
PSEG Power's share of Contribution	$206,101	$121,760	$143,600	-$7,616	$247,583	$104,990	$80,646
CIG Interuptible Contribution to BGSSR	$719,721	$329,585	$394,390	-$29,260	$2,810,880	$1,188,530	$587,423
TSG-F:							
TSG-F SBC Rate adjustment (line 84)							
TSG-F Sales Therms	2,292,657	1,175,577	1,860,546	3,288,560	2,053,802	2,840,959	5,886,671
TSG-F Gross Revenues	$303,005	$128,361	$615,239	$624,623	$459,232	$549,301	$820,938
TSG-F SBC/GPRC Revenues	$109,034	$55,908	$88,484	$156,397	$97,675	$135,110	$278,345
TSG-F TEFA Revenues	$0	$0	$0	$0	$0	$0	$0
TSG-F MAC Revenues	-$14,531	-$7,451	-$11,792	-$20,843	-$13,017	-$18,006	-$37,310
TSG-F PSEG Power's share of Contribution	$65,127	$107,231	$109,829	$144,554	$121,375	$131,179	$93,158
TSG-F Interuptible Contribution to BGSSR	$143,375	-$27,327	$428,719	$344,515	$253,199	$301,018	$486,744
Cogen Contracts :							
NewMarket Settlement Incl. in Cogen Rev. row 35 (add back C&I Portion)							
Cogen Contract Therms	0	0	0	0	0	0	0
Cogen Contract Gross Revenues	-	-	-	-	-	-	-
Cogen Contract RAC Revenues	-	-	-	-	-	-	-
Contract Cogen - Resale	-	-	-	-	-	-	-
JCPL (NJ Natural Deliveries) reduction to expense	$0	$0	$0	$0	$0	$0	$0
Cogen Contract Cost & PSEG Power's share of Contribution	$0	$0	$0	$0	$0	$0	$0
Cogen Contract Contribution	$0	$0	$0	$0	$0	$0	$0
CSG NON-Power:							
CSG Non-Power Therms	27,025,052	(13,590,077)	(632,154)	3,342,543	33,809,225	2,079,373	13,281,838
CSG Non-Power Revenues	399,035	201,225	260,117	262,914	609,578	196,910	446,678
CSG Non Power SBC Revenues	396,414	274,693	297,078	260,319	260,319	281,347	185,772
CSG Non-Power ER&T's share of Contribution	66,782	58,200	(18,243)	22,824	25,565	22,245	25,395
CSG Non-Power Contribution to BGSSR	(64,161)	(131,668)	(18,718)	(20,228)	323,694	(106,682)	235,511
Total Interruptible Contributions	903,398	300,681	878,726	341,981	5,257,160	1,514,236	431,617
SBC & GPRC rate-CIG & TSG-F (CHECK tariff pages for rate changes)	**0.047558**	**0.047558**	**0.047558**	**0.047558**	**0.047558**	**0.047558**	**0.047284**
TEFA rate-TSG-F **(Reduced 25% 2012 & 25% 2013, zero out 2014)**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Cogen Contract RAC rate (separate schedule beginning 12/02)	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**
MAC rate-TSG-F **(Per MAC CALC Worksheet)**	**-0.006338**	**-0.006338**	**-0.006338**	**-0.006338**	**-0.006338**	**-0.006338**	**-0.006338**

Current Month Estimate - Gas Purchases (1) See below row 96	$12,661,134	$58,465,903	$91,114,491	$94,386,834	$69,501,866	$85,818,735	$49,427,255
Prior Month Actual - Gas Purchases (1) See below row 105	$4,845,755	$11,749,393	$57,760,451	$89,985,443	$91,844,427	$67,745,658	$85,705,876
Prior Month Estimate - Gas Purchases See below row 115	$4,366,087	$12,661,134	$58,465,903	$91,114,491	$94,386,834	$69,501,866	$85,818,735
Gas Purchases	$13,140,801	$57,554,162	$90,409,039	$93,257,786	$66,959,459	$84,062,527	$49,314,396
Gas Refunds	$0	$0	$0	$0	$0	$0	$0
ISG (BGSS-I) Cost Est. (2)	$37,610	$141,404	$229,216	$647,853	$380,915	$353,861	$152,900
PSEG Power's share of Contribution CMnth Est. (2)	$29,132	$29,720	$49,684	$30,992	$98,963	$59,394	$35,972
ISG (BGSS-I) Cost Pr Mnth Act. (2)	$45,417	$30,696	$151,441	$219,303	$649,315	$371,605	$365,459
PSEG Power's share of Contribution Pr Mnth Act. (2)	$28,889	$27,149	$32,422	$48,120	$545,225	$104,232	$58,900
ISG (BGSS-I) Cost PrMnth Est.	$46,130	$37,610	$141,404	$229,216	$647,853	$380,915	$353,861
PSEG Power's share of Contribution PrMnth Est.	$31,042	$29,132	$29,720	$49,684	$30,992	$98,963	$59,394
CIG Cost (3) - CMnth Est. (3)	$364,205	$745,854	$1,020,143	$1,320,925	$935,330	$1,067,095	$614,075
PSEG Power's share of Contribution - CMnth Est. (3)	$220,009	$94,906	$137,080	-$9,757	$166,952	$90,950	$85,499
CIG Cost (3) - PrMnth Act. (3)	$398,650	$357,312	$801,323	$1,030,432	$1,314,322	$929,156	$1,103,521
PSEG Power's share of Contribution - PrMnth Act. (3)	$191,860	$246,863	$101,426	$139,221	$70,874	$180,992	$86,097
CIG Cost - PrMnth Est.	$405,062	$364,205	$745,854	$1,020,143	$1,320,925	$935,330	$1,067,095
PSEG Power's share of Contribution - PrMnth Est.	$205,768	$220,009	$94,906	$137,080	-$9,757	$166,952	$90,950
TSG-F PSEG Power's share of Contribution CMth Est. (4)	$70,499	$99,058	$97,902	$130,452	$112,176	$128,088	$87,184
TSG-F PSEG Power's share of Contribution PrMth Actual (4)	$64,391	$78,671	$110,985	$112,004	$139,651	$115,266	$134,062
TSG-F PSEG Power's share of Contribution PrMth Est.	$69,763	$70,499	$99,058	$97,902	$130,452	$112,176	$128,088
CSC Non-Power Cost & PSEG Power's share of Contribution CMth Est. (6)	$87,451	$78,650	$21,407	$22,102	$23,440	$22,807	$21,937
CSC Non-Power Cost & PSEG Power's share of Contribution PMth Act. (6)	$90,845	$67,001	$39,000	$22,129	$24,227	$22,877	$26,264
CSC Non-Power Cost & PSEG Power's share of Contribution PMth Est.	$111,514	$87,451	$78,650	$21,407	$22,102	$23,440	$22,807
BGSS-RSG Prior Month Actual	$5,510,570	$12,411,415	$58,847,063	$91,422,519	$94,424,163	$69,331,643	$87,319,852
BGSS-RSG Cogen Contracts Prior Month Actual (6)	$0	$0	$0	$0	$0	$0	$0
BGSS-RSG TSG Cashouts Prior Mnth Actuals	$0	$0	$0	$0	$0	$0	$0
Subtotal	$5,799,991	$12,801,450	$59,016,624	$91,709,891	$94,715,554	$69,542,258	$87,568,120
Total BGSS-RSG Actual Bill	**$5,799,991**	**$12,801,450**	**$59,016,624**	**$91,709,891**	**$94,715,554**	**$69,542,258**	**$87,568,120**
Difference	$0	$0	$0	$0	$0	$0	$0
BGSS-RSG Current Month Estimate	$13,685,309	$59,636,429	$92,832,874	$96,701,122	$71,292,110	$87,635,766	$50,689,133
BGSS-RSG Cogen Contracts Prior Month Estimate (6)	$0	$0	$0	$0	$0	$0	$0
Subtotal	$13,685,309	$59,636,429	$92,832,874	$96,701,122	$71,292,110	$87,635,766	$50,689,133
Total BGSS-RSG Estimate Bill	**$13,685,309**	**$59,636,429**	**$92,832,874**	**$96,701,122**	**$71,292,110**	**$87,635,766**	**$50,689,133**
Difference	$0	$0	$0	$0	$0	$0	$0

Gas Purchases Details:
Current Month Estimate

BGSS-RSG GAS COMMODITY VOLUMES MDTh	5,362,185	16,312,433	27,087,300	30,323,113	19,509,937	21,813,284	13,735,323
BGSS-RSG GAS COMMODITY COST	$19,810,400	$60,830,156	$99,591,871	$116,753,532	$75,917,233	$86,775,360	$52,670,625
BGSS-RSG Balancing	$588,500	$3,012,306	$5,152,404	$5,823,482	$3,667,428	$4,146,517	$1,507,452
BGSS-RSG Off System Sales	($6,490,677)	($4,869,515)	($12,635,679)	($27,236,575)	($9,349,540)	($4,239,420)	($3,493,605)
Electric Reservation Charge	($873,870)	($348,403)	($711,846)	($629,330)	($525,170)	($617,991)	($883,785)
CSG Revenues	($373,219)	($158,642)	($282,260)	($324,275)	($208,084)	($245,731)	($373,432)
Credit for Pipeline Refunds	$0	$0	$0	$0	$0	$0	$0

Total	$12,661,134	$58,465,903	$91,114,491	$94,386,834	$69,501,866	$85,818,735	$49,427,255

Prior Actual							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,142,210	5,066,031	16,016,745	26,730,108	29,619,065	19,097,402	21,735,257
BGSS-RSG GAS COMMODITY COST	$11,949,517	$18,726,370	$59,862,702	$98,416,385	$113,770,503	$74,159,837	$86,654,521
BGSS-RSG Balancing	$344,858	$555,997	$2,937,419	$5,083,866	$5,682,744	$3,600,783	$4,108,903
BGSS-RSG Off System Sales	-$6,539,715	-$6,263,231	-$4,511,550	-$12,504,231	-$26,683,231	-$9,261,939	-$4,185,980
Electric Reservation Charge	-$624,422	-$879,882	-$353,649	-$722,745	-$633,301	-$530,147	-$623,000
CSG Revenues	-$289,422	-$390,035	-$169,561	-$287,372	-$291,391	-$210,615	-$248,268
Non Compliance Penalty	$0	$0	$0	$0	$0	$0	$0
Credit for Pipeline Refunds	$0	$0	$0	$0	$0	$0	$0
Adjustment for Send Out Volumes	$0	$0	$0	$0	$0	$0	$0
Adjustment for Shared OFS Margins Due to Billing Adjustment	$0	$0	$0	$0	$0	$0	$0
Reverse Original Entry of Utility Share of Transco Fuel Surcharge	$0	$0	$0	$0	$0	$0	$0
Utility's Share of Fuel Refund Paid to Transco	$0	$0	$0	$0	$0	$0	$0
Utility Share of Reservation Charge Adjustment	$0	$0	$0	$0	$0	$0	$0
Utility's Share of Revenue Adjustment (GCAP Book)	$0	$0	$0	$0	$0	$0	$0
Utility Share of Tennessee Fuel Surcharge (For 04/1999 to 03/2003)	$0	$0	$0	$0	$0	$0	$0
Utility Share of Tennessee Fuel Surcharge (For 04/2003 to 01/2004)	$0	$0	$0	$0	$0	$0	$0
Residential Share of Propane Contract Deficiency Charges	$5,506	$1,847	$0	-$216	$0	$0	$0
Residential Share of Property Taxes Paid	$0	$0	$0	$0	$0	$0	$0
Prior Period Adjustments	-$567	-$1,673	-$4,911	-$244	-$898	-$12,261	-$301
Residential Share of Hattisburg Tax Payment	$0	$0	$0	$0	$0	$0	$0
Total	$4,845,755	$11,749,393	$57,760,451	$89,985,443	$91,844,427	$67,745,658	$85,705,876

Prior Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	2,959,292	5,362,185	16,312,433	27,087,300	30,323,113	19,509,937	21,813,284
BGSS-RSG GAS COMMODITY COST	$11,263,610	$19,810,400	$60,830,156	$99,591,871	$116,753,532	$75,917,233	$86,775,360
BGSS-RSG Balancing	$324,782	$588,500	$3,012,306	$5,152,404	$5,823,482	$3,667,428	$4,146,517
BGSS-RSG Off System Sales	($6,332,464)	($6,490,677)	($4,869,515)	($12,635,679)	($27,236,575)	($9,349,540)	($4,239,420)
Electric Reservation Charge	($619,306)	($873,870)	($348,403)	($711,846)	($629,330)	($525,170)	($617,991)
Prior CSG Revenues	($270,535)	($373,219)	($158,642)	($282,260)	($324,275)	($208,084)	($245,731)
Credit for Pipeline Refunds	$0	$0	$0	$0	$0	$0	$0
Total	$4,366,087	$12,661,134	$58,465,903	$91,114,491	$94,386,834	$69,501,866	$85,818,735

Net							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	5,545,103	16,016,279	26,791,612	29,965,921	18,805,889	21,400,749	13,657,296
BGSS-RSG GAS COMMODITY COST	$20,496,307	$59,746,126	$98,624,417	$115,578,046	$72,934,204	$85,017,964	$52,549,786
BGSS-RSG Balancing	$608,575	$2,979,803	$5,077,517	$5,754,943	$3,526,690	$4,079,872	$1,469,838
BGSS-RSG Off System Sales	($6,697,928)	($4,642,068)	($12,277,713)	($27,105,128)	($8,796,196)	($4,151,819)	($3,440,164)
Electric Reservation Charge	($878,986)	($354,414)	($717,092)	($640,228)	($529,141)	($622,969)	($888,793)
Other	$4,939	$174	($4,911)	($460)	($898)	($12,261)	($301)
CSG Revenues	($392,105)	($175,459)	($293,178)	($329,387)	($175,201)	($248,261)	($375,970)
Credit for Pipeline Refunds	$0	$0	$0	$0	$0	$0	$0
Total	$13,140,801	$57,554,162	$90,409,039	$93,257,786	$66,959,459	$84,062,527	$49,314,396
BGSS-RSG GAS COMMODITY VOLUMES MDTh	5,545,103	16,016,279	26,791,612	29,965,921	18,805,889	21,400,749	13,657,296
NET SALES VOLUMES RESIDENTIAL	4,575,522	14,510,892	25,469,524	28,833,692	19,416,173	21,756,885	13,498,106
Diff	969,581	1,505,387	1,322,088	1,132,229	(610,284)	(356,136)	159,190

Interest Calculation
For Period Oct 17 to Sept 18

	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18
CUMULATIVE OVER/(UNDER) RECOVERY PRIOR MONTH	$993,487.21	$4,241,571.64	$8,746,149.08	$29,909,705.43	$24,289,522.33	$19,450,642.90	($6,779,906.09)
CUMULATIVE OVER/(UNDER) RECOVERY CURRENT MONTH	$4,223,723.56	$8,684,082.34	$29,716,059.48	$23,911,753.16	$18,925,036.73	($7,346,919.10)	($28,173,972.88)
AVERAGE BALANCE	$2,608,605.39	$6,462,826.99	$19,231,104.28	$26,910,729.30	$21,607,279.53	$6,051,861.90	($17,476,939.48)
MONTHLY INTEREST (Income)/Expense, 8/10 @ .006842	**$17,848.08**	**$44,218.66**	**$131,579.22**	**$184,123.21**	**$147,837.01**	**$41,406.84**	**($119,577.22)**
INTEREST ACCUMULATED, (Income)/Expense	$17,848.08	$62,066.74	$193,645.96	$377,769.17	$525,606.17	$567,013.01	$447,435.79

8. Wholesale Gas Pricing Assumptions

Item 8

A Comparison of the Forecasted Cost of Gas as represented by the NYMEX
June 2018 Filing versus June 2017 Filing

($/Mbtu)

		June '18 Filing Nymex - 5/10/18	June '17 Filing Nymex - 5/10/17	Difference	Percentage Difference
2018	**May**	$2.821	$3.142	($0.321)	-10.2%
	June	$2.814	$3.292	($0.478)	-14.5%
	July	$2.828	$3.380	($0.552)	-16.3%
	August	$2.836	$3.412	($0.576)	-16.9%
	September	$2.822	$3.394	($0.572)	-16.9%
	October	$2.829	$3.414	($0.585)	-17.1%
	November	$2.865	$3.461	($0.596)	-17.2%
	December	$2.965	$3.580	($0.615)	-17.2%
2019	**January**	$3.047	$3.655	($0.608)	-16.6%
	February	$3.009	$3.618	($0.609)	-16.8%
	March	$2.898	$3.520	($0.622)	-17.7%
	April	$2.568	$2.955	($0.387)	-13.1%
	May	$2.536	$2.888	($0.352)	-12.2%
	June	$2.567	$2.912	($0.345)	-11.8%
	July	$2.600	$2.936	($0.336)	-11.4%
	August	$2.604	$2.942	($0.338)	-11.5%
	September	$2.588	$2.918	($0.330)	-11.3%
	Average	$2.776	$3.260	($0.484)	-14.8%

9. GCUA Recoveries and Balances

N/A

10. Historical Service Interruptions

Item 10

SERVICE INTERRUPTIONS

During the current winter, service to the Company's tariff gas customers was interrupted during the following time periods:

Note: All dates below represent heating season for year 2017-2018.

Rate Schedule CIG:
Number of Customers: 13 (including 4 CEGs)
10:00 AM December 31 through 10:00 AM January 2
(CEG was offered at $16.43/Dth,
10:00 AM January 4 through 10:00 AM January 8
(CEG was offered at $10.90/Dth, only for the period 10:00AM January 4 through 10:00AM January 5; then CEG was offered at $15.98/Dth for the period 10:00AM January 7 through 10:00AM January 8)

Rate Schedule TSG-NF (BGSS-I):
Number of Customers: 16
10:00 AM December 28 through 10:00 AM January 2
10:00 AM January 4 through 10:00 AM January 8

Rate Schedule TSG-NF (Third Party Suppliers):
Number of Customers: 155
10:00 AM December 31 through 10:00 AM January 2
10:00 AM January 4 through 10:00 AM January 8

Rate Schedule CSG-I (Third Party Suppliers):
Number of Customers: 3
10:00 AM December 31 through 10:00 AM January 2
10:00 AM January 4 through 10:00 AM January 8

All of the above interruptions were done for operational reasons.

11. Gas Price Hedging Activities

Reports Dated:

April 4, 2018

January 4, 2018

October 3, 2017

July 6, 2017

Matthew M. Weissman
General Regulatory Counsel - Rates

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
tel : 973-430-7052 fax: 973-430-5983
email: matthew.weissman@pseg.com

PSEG
Services Corporation

April 4, 2018

In the Matter of Public Service Electric and Gas Company
Proposal for a Change in its Monthly Pricing Mechanism
Within its Levelized Gas Adjustment Clause for Residential
Gas Customers Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1
Docket No. GR00070491

VIA ELECTRONIC MAIL

Thomas Walker, Director
Division of Energy
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – FIRST QUARTER 2018

Dear Director Walker:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of March 31, 2018.

As shown on the attached schedules, approximately 99% of the planned residential volume has been completed for the 2018 summer season and 62% of the plan has been completed for the 2018/19 winter. Hedging for the 2019 summer is at 32% of plan. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

The Company will continue to monitor the performance of its hedging program and the criteria it utilizes deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Stacy Peterson

PSE&G Residential Hedging Report November 2017 - October 2018 As of 3/31/2018	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 17-Mar 18 Hedge Volume (230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**17.37**	94%	100%	99%	**$2.61**
Dollar Budget Method	17.500	**17.410**	$2.515M/mo.		99%	**$2.42**
Total Winter Hedge Volume	35.000	**34.775**			99%	**$2.51**
			Current NYMEX Strip ===>			**$2.97**
SUMMER - Apr 18-Oct 18 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**17.120**	94%	100%	98%	**$2.27**
Dollar Budget Method	17.500	**17.420**	$2.132M/mo.		100%	**$2.18**
Total Summer Hedge Volume	35.000	**34.540**			99%	**$2.22**
			Current NYMEX Strip ===>			**$2.72**
Total Non-Discretionary Method	35.000	**34.485**				**$2.44**
Total Dollar Budget Method	35.000	**34.830**				**$2.30**
					Difference	**($0.14)**
					Percent	**-6.2%**

PSE&G Residential Hedging Report November 2018 - October 2019 As of 3/31/2018	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 18-Mar 19 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**11.325**	56%	61%	65%	**$2.61**
Dollar Budget Method	17.500	**10.238**	$2.464M/mo.		59%	**$2.59**
Total Winter Hedge Volume	35.000	**21.563**			62%	**$2.60**
			Current NYMEX Strip ===>			**$2.94**
SUMMER - Apr 19-Oct 19 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**5.350**	28%	33%	31%	**$2.05**
Dollar Budget Method	17.500	**5.906**	$2.050M/mo.		34%	**$2.06**
Total Summer Hedge Volume	35.000	**11.256**			32%	**$2.05**
			Current NYMEX Strip ===>			**$2.65**
Total Non-Discretionary Method	35.000	**16.675**				**$2.43**
Total Dollar Budget Method	35.000	**16.144**				**$2.40**
					Difference	**($0.03)**
					Percent	**-1.4%**

Matthew M. Weissman
General Regulatory Counsel - Rates

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
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PSEG Services Corporation

January 4, 2018

In the Matter of Public Service Electric and Gas Company
Proposal for a Change in its Monthly Pricing Mechanism
Within its Levelized Gas Adjustment Clause for Residential
Gas Customers Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1
Docket No. GR00070491

VIA ELECTRONIC MAIL

Thomas Walker, Director
Division of Energy
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – FOURTH QUARTER 2017

Dear Director Walker:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of December 31, 2017.

As shown on the attached schedules, approximately 99% of the planned residential volume has been completed for the 2017/18 winter season and 81% of the plan has been completed for the 2018 summer. Hedging for the 2018/19 winter is at 45% of plan and hedging for the 2019 summer is at 18% of plan. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

The Company will continue to monitor the performance of its hedging program and the criteria it utilizes deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Mark Beyer

PSE&G Residential Hedging Report
November 2017 - October 2018
As of 12/31/2017

	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 17-Mar 18 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**17.37**	94%	100%	99%	**$2.61**
Dollar Budget Method	17.500	**17.410**	$2.515M/mo.		99%	**$2.42**
Total Winter Hedge Volume	35.000	**34.775**			99%	**$2.51**
			Current NYMEX Strip ===>			**$2.90**
SUMMER - Apr 18-Oct 18 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**13.910**	78%	83%	79%	**$2.30**
Dollar Budget Method	17.500	**14.424**	$2.132M/mo.		82%	**$2.19**
Total Summer Hedge Volume	35.000	**28.334**			81%	**$2.24**
			Current NYMEX Strip ===>			**$2.82**
Total Non-Discretionary Method	35.000	**31.275**				**$2.47**
Total Dollar Budget Method	35.000	**31.834**				**$2.32**
					Difference	**($0.16)**
					Percent	**-6.7%**

PSE&G Residential Hedging Report November 2018 - October 2019 As of 12/31/2017	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 18-Mar 19 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**8.31**	39%	44%	47%	**$2.63**
Dollar Budget Method	17.500	**7.399**	$2.464M/mo.		42%	**$2.61**
Total Winter Hedge Volume	35.000	**15.704**			45%	**$2.62**
			Current NYMEX Strip ===>			**$3.03**
SUMMER - Apr 19-Oct 19 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**3.210**	11%	17%	18%	**$2.06**
Dollar Budget Method	17.500	**2.953**	$2.050M/mo.		17%	**$2.05**
Total Summer Hedge Volume	35.000	**6.163**			18%	**$2.05**
			Current NYMEX Strip ===>			**$2.70**
Total Non-Discretionary Method	35.000	**11.515**				**$2.47**
Total Dollar Budget Method	35.000	**10.352**				**$2.45**
					Difference	**($0.02)**
					Percent	**-1.0%**

Matthew M. Weissman
General Regulatory Counsel - Rates

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
tel : 973-430-7052 fax: 973-430-5983
email: matthew.weissman@pseg.com

October 3, 2017

In the Matter of Public Service Electric and Gas Company
Proposal for a Change in its Monthly Pricing Mechanism
Within its Levelized Gas Adjustment Clause for Residential
Gas Customers Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1
Docket No. GR00070491

VIA ELECTRONIC MAIL

Thomas Walker, Director
Division of Energy
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – THIRD QUARTER 2017

Dear Director Walker:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of September 30, 2017.

As shown on the attached schedules, approximately 95% of the planned residential volume has been completed for the 2017/18 winter season and 67% of the plan has been completed for the 2018 summer. Hedging for the 2018/19 winter is at 26% of plan and we have not begun to hedge for the 2019 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

The Company will continue to monitor the performance of its hedging program and the criteria it utilizes deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Mark Beyer

PSE&G Residential Hedging Report November 2017 - October 2018 As of 9/30/2017	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 17-Mar 18 Hedge Volume (230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**16.61**	94%	100%	95%	**$2.60**
Dollar Budget Method	17.500	**16.504**	$2.515M/mo.		94%	**$2.55**
Total Winter Hedge Volume	35.000	**33.114**			95%	**$2.58**
			Current NYMEX Strip ===>			**$3.25**
SUMMER - Apr 18-Oct 18 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**11.770**	61%	67%	67%	**$2.30**
Dollar Budget Method	17.500	**11.556**	$2.132M/mo.		66%	**$2.18**
Total Summer Hedge Volume	35.000	**23.326**			67%	**$2.24**
			Current NYMEX Strip ===>			**$2.95**
Total Non-Discretionary Method	35.000	**28.380**				**$2.48**
Total Dollar Budget Method	35.000	**28.060**				**$2.40**
					Difference	**($0.08)**
					Percent	**-3.2%**

PSE&G Residential Hedging Report November 2018 - October 2019 As of 9/30/2017	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 18-Mar 19 Hedge Volume (230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**4.53**	26%	33%	26%	**$2.64**
Dollar Budget Method	17.500	**4.741**	$2.464M/mo.		27%	**$2.58**
Total Winter Hedge Volume	35.000	**9.271**			26%	**$2.61**
			Current NYMEX Strip ===>			**$3.15**
SUMMER - Apr 19-Oct 19 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**0.000**	0%	0%	0%	**$0.00**
Dollar Budget Method	17.500	**0.000**	$XXXM/mo.		0%	**$0.00**
Total Summer Hedge Volume	35.000	**0.000**			0%	**#DIV/0!**
			Current NYMEX Strip ===>			**$2.76**
Total Non-Discretionary Method	35.000	**4.530**				**$2.64**
Total Dollar Budget Method	35.000	**4.741**				**$2.58**
					Difference	**($0.06)**
					Percent	**-2.4%**

Matthew M. Weissman
General Regulatory Counsel - Rates

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PSEG
Services Corporation

July 6, 2017

In the Matter of Public Service Electric and Gas Company
Proposal for a Change in its Monthly Pricing Mechanism
Within its Levelized Gas Adjustment Clause for Residential
Gas Customers Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1
Docket No. GR00070491

VIA ELECTRONIC MAIL

Thomas Walker, Director
Division of Energy
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – SECOND QUARTER 2017

Dear Director Walker:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of June 30, 2017.

As shown on the attached schedules, approximately 81% of the planned residential volume has been completed for the 2017/18 winter season and 50% of the plan has been completed for the 2018 summer. Hedging for the 2018/19 winter is at 12% of plan and we have not begun to hedge for the 2019 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

The Company will continue to monitor the performance of its hedging program and the criteria it utilizes deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Mark Beyer

PSE&G Residential Hedging Report November 2017 - October 2018 As of 6/30/2017	**Bcf Target***	**Bcf Hedged**	**% Hedged Target**		**% Hedged Actual**	**Current Price/ MMBtu**
WINTER - Nov 17-Mar 18 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**14.52**	78%	83%	83%	**$2.58**
Dollar Budget Method	17.500	**13.676**	$2.515M/mo.		78%	**$2.54**
Total Winter Hedge Volume	35.000	**28.192**			81%	**$2.56**
			Current NYMEX Strip ===>			**$3.20**
SUMMER - Apr 18-Oct 18 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**8.560**	44%	50%	49%	**$2.28**
Dollar Budget Method	17.500	**8.774**	$2.132M/mo.		50%	**$2.15**
Total Summer Hedge Volume	35.000	**17.334**			50%	**$2.22**
			Current NYMEX Strip ===>			**$2.82**
Total Non-Discretionary Method	35.000	**23.076**				**$2.47**
Total Dollar Budget Method	35.000	**22.450**				**$2.38**
					Difference	**($0.08)**
					Percent	**-3.5%**

PSE&G Residential Hedging Report November 2018 - October 2019 As of 6/30/2017	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 18-Mar 19 Hedge Volume (230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**2.27**	6%	11%	13%	**$2.64**
Dollar Budget Method	17.500	**1.933**	$2.464M/mo.		11%	**$2.54**
Total Winter Hedge Volume	35.000	**4.198**			12%	**$2.59**
			Current NYMEX Strip ===>			**$3.02**
SUMMER - Apr 19-Oct 19 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**0.000**	0%	0%	0%	**$0.00**
Dollar Budget Method	17.500	**0.000**	$XXXM/mo.		0%	**$0.00**
Total Summer Hedge Volume	35.000	**0.000**			0%	**#DIV/0!**
			Current NYMEX Strip ===>			**$2.72**
Total Non-Discretionary Method	35.000	**2.265**				**$2.64**
Total Dollar Budget Method	35.000	**1.933**				**$2.54**
					Difference	**($0.10)**
					Percent	**-3.8%**

12. Storage Gas Volumes, Prices and Utilization

Ending Storage Inventory by Contract

Mdth

Storage Contract	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18
DTI GSS	15,883.3	14,085.2	11,668.7	9,336.6	8,371.0	4,589.8	3,274.7
ARLINGTON	4,405.0	3,569.1	2,607.8	1,312.2	544.4	0.0	0.0
TR GSS	15,237.2	15,029.2	12,487.9	10,315.5	8,300.0	4,077.2	2,465.6
TR S-2	5,876.3	5,601.8	4,161.3	2,764.6	1,375.0	366.4	492.4
TR LSS	4,950.9	4,484.7	3,512.6	2,839.3	2,126.4	1,053.2	1,265.8
TENN FS-MA	2,684.4	2,759.1	2,852.7	2,850.4	2,597.9	2,454.0	2,329.7
DTI GSS-TE	14,105.9	13,044.3	10,524.7	7,602.7	6,102.2	3,520.5	2,629.4
TE SS-1 / SS	1,452.5	1,394.0	1,162.8	824.3	479.8	162.7	172.7
TE SS1	3,735.0	3,580.4	2,989.4	2,022.4	1,271.7	572.3	537.5
TR ESS	1,186.5	1,186.5	1,064.4	1,000.0	1,185.3	1,186.5	1,182.5
GULF SOUTH	1,000.0	1,000.0	923.5	781.7	1,000.0	1,000.0	941.5
TR LNG	1,333.8	1,259.7	1,141.2	1,131.8	1,131.8	984.7	1,107.5
TR LNG New	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Total	71,866.4	67,009.4	55,112.5	42,797.3	34,501.0	19,982.7	16,414.8
Ending Inventory Cost ($/Dth)	$3.70	$3.74	$3.68	$3.83	$3.88	$3.99	$3.82

NOTE: All volumes shown above represent total storage for all firm customers while the average inventory cost is applicable to residential only.

LPG INVENTORY VOLUMES AND COST BY LOCATION
(000)

	Camden		Central		Harrison		Linden	
Month	**Dth**	**Dollars**	**Dth**	**Dollars**	**Dth**	**Dollars**	**Dth**	**Dollars**
Jan-15	54	$662	106	$1,434	92	$1,435	59	$754
Feb-15	46	$571	90	$1,221	75	$1,158	59	$754
Mar-15	46	$571	90	$1,221	75	$1,158	59	$754
Apr-15	38	$475	43	$579	41	$588	41	$520
May-15	38	$475	43	$579	41	$588	41	$520
Jun-15	38	$475	43	$579	41	$579	41	$520
Jul-15	38	$475	43	$579	66	$775	41	$520
Aug-15	45	$526	79	$753	72	$823	56	$593
Sep-15	45	$526	82	$769	72	$823	56	$593
Oct-15	45	$526	82	$769	72	$823	56	$593
Nov-15	45	$526	82	$769	72	$823	56	$593
Dec-15	48	$548	89	$827	80	$889	56	$593
Jan-16	48	$548	88	$816	80	$889	56	$593
Feb-16	47	$542	88	$816	77	$852	56	$593
Mar-16	47	$542	84	$794	63	$672	48	$510
Apr-16	47	$542	84	$794	73	$748	48	$510
May-16	47	$537	84	$794	72	$739	48	$510
Jun-16	47	$537	84	$794	72	$739	48	$510
Jul-16	47	$537	84	$794	72	$739	48	$510
Aug-16	47	$537	84	$794	72	$739	77	$667
Sep-16	47	$537	87	$816	72	$739	77	$667
Oct-16	47	$537	92	$858	80	$811	78	$671
Nov-16	47	$537	92	$858	80	$811	78	$671
Dec-16	47	$537	94	$858	81	$811	62	$531

LPG INVENTORY VOLUMES AND COST BY LOCATION
(000)

Month		Camden Dth	Camden Dollars	Central Dth	Central Dollars	Harrison Dth	Harrison Dollars	Linden Dth	Linden Dollars
Jan-17		46	$ 528	91	$ 836	78	$ 781	62	$ 531
Feb-17		46	$ 528	91	$ 836	78	$ 781	62	$ 531
Mar-17		46	$ 528	85	$ 780	70	$ 694	62	$ 531
Apr-17		46	$ 528	92	$ 835	70	$ 694	55	$ 476
May-17		46	$ 528	92	$ 835	76	$ 748	49	$ 422
Jun-17		46	$ 528	92	$ 835	76	$ 748	49	$ 422
Jul-17		46	$ 528	92	$ 835	76	$ 748	49	$ 422
Aug-17		46	$ 528	92	$ 835	76	$ 748	49	$ 422
Sep-17		46	$ 528	92	$ 835	76	$ 748	60	$ 550
Oct-17		46	$ 528	92	$ 835	76	$ 748	60	$ 549
Nov-17		46	$ 528	92	$ 835	76	$ 748	60	$ 549
Dec-17		46	$ 521	91	$ 828	73	$ 725	60	$ 544
Jan-18		45	$ 510	88	$ 802	71	$ 698	60	$ 544
Feb-18		42	$ 480	65	$ 588	35	$ 342	60	$ 544
Mar-18		42	$ 480	65	$ 588	35	$ 342	60	$ 544
Apr-18	est	42	$ 480	65	$ 588	35	$ 342	60	$ 544
May-18	est	42	$ 480	65	$ 588	35	$ 342	60	$ 544
Jun-18	est	42	$ 480	65	$ 588	35	$ 342	60	$ 544
Jul-18	est	42	$ 480	65	$ 588	35	$ 342	60	$ 544
Aug-18	est	42	$ 480	65	$ 588	35	$ 342	60	$ 544
Sep-18	est	42	$ 480	65	$ 588	35	$ 342	60	$ 544
Oct-18	est	42	$ 480	65	$ 588	35	$ 342	60	$ 544
Nov-18	est	42	$ 480	65	$ 588	35	$ 342	60	$ 544
Dec-18	est	42	$ 480	65	$ 588	35	$ 342	60	$ 544

LNG INVENTORY VOLUMES AND COST
(000)

Month	Dth	Dollars	Month		Dth	Dollars
Jan-15	240	$488	Jan-17		355	$328
Feb-15	144	$292	Feb-17		177	$163
Mar-15	224	$284	Mar-17		179	$168
Apr-15	324	$423	Apr-17		160	$150
May-15	368	$515	May-17		200	$195
Jun-15	362	$507	Jun-17		190	$187
Jul-15	355	$497	Jul-17		184	$180
Aug-15	349	$489	Aug-17		177	$174
Sep-15	349	$487	Sep-17		171	$167
Oct-15	351	$486	Oct-17		151	$148
Nov-15	344	$477	Nov-17		203	$213
Dec-15	334	$463	Dec-17		165	$174
Jan-16	327	$453	Jan-18		129	$136
Feb-16	174	$241	Feb-18		122	$128
Mar-16	236	$253	Mar-18		198	$207
Apr-16	325	$378	Apr-18	est	190	$199
May-16	331	$396	May-18	est	190	$199
Jun-16	322	$393	Jun-18	est	190	$199
Jul-16	314	$383	Jul-18	est	190	$199
Aug-16	306	$373	Aug-18	est	190	$199
Sep-16	442	$376	Sep-18	est	190	$199
Oct-16	419	$386	Oct-18	est	190	$199
Nov-16	404	$372	Nov-18	est	190	$199
Dec-16	376	$346	Dec-18	est	190	$199

13. <u>Affiliate Gas Supply Transactions</u>

Item 13

Principal Terms of the Requirements Contract between PSE&G and PSEG Energy Resources & Trade (ER&T)

1. Effective Date: May 1, 2002, as amended March 31, 2007 and April 1, 2014
2. Supply Obligation: In daily consultation with PSE&G, ER&T is obligated to supply Basic Gas Supply Service ("BGSS") to PSE&G
   - BGSS is the retail gas supply service, by which ER&T provides all needed firm and non-firm gas to PSE&G to meet the natural gas requirements of its customers, including:
     - PSE&G's firm obligations
     - PSE&G's balancing services
     - PSE&G's non-firm supply obligations
     - PSE&G's non-tariff service agreements
   - To meet this obligation, ER&T holds all the necessary firm transportation, storage and gas purchase contracts to reliably serve PSE&G, as they may change over time
     - Gas capacity, storage, and transportation contracts were transferred from PSE&G to ER&T

    - Natural gas, LNG, and propane inventories were transferred from PSE&G to ER&T at book value as of April 30, 2002
    - BPU order authorizing the transfer was entered April 17, 2002
  - ER&T provides administrative and management services to PSE&G related to the wholesale delivery of gas, including:
    - Load scheduling
    - Load balancing
    - Mitigation of price volatility
    - When appropriate, input into decisions regarding whether to interrupt service and when to call upon peak shaving
  - PSE&G maintains peak shaving facilities, for which ER&T pays operating and maintenance costs, and also return
  - Deliveries of BGSS services are to be made to PSE&G at pipeline or peak shaving interconnections
    - ER&T is responsible for transportation of gas to the Points of Delivery, and PSE&G is responsible for transportation of gas from the Points of Delivery
  - ER&T is the sole supplier of the BGSS full requirements

3. Term: Through March 31, 2019, and year-to-year thereafter, subject to cancellation by either party with 2 years notice
  - Original term was to March 31, 2004, with option to extend

- Revised term was to March 31, 2007, and year-to-year thereafter
- Further revised term was to March 31, 2012, and year-to-year thereafter

4. Quality: The quality of gas delivered to PSE&G shall conform with the specifications of ER&T's interstate transportation providers, with the exception of refinery, landfill, and peaking gas, which shall be blended
5. Pressure: The pressure of gas delivered to PSE&G shall conform with the specifications of ER&T's interstate transportation providers
6. Default: PSE&G may recall all BGSS assets upon a default by ER&T
7. Warranty: ER&T warrants that:
    - It holds good Title to gas it sells
    - It holds sufficient entitlements to provide the full requirements services
8. Interruptible Loads: PSE&G is responsible for curtailing interruptible loads when appropriate
9. Payment: PSE&G pays ER&T monthly for these services:
    - All gas supply and capacity charges
    - Balancing
10. Non-Tariff Services: Non-tariff service to cogenerators is provided
11. Regulatory: The contract is subject to regulatory oversight, and ER&T shall supply expert witness testimony in any BPU proceeding concerning the gas component of any rate.

14. Supply and Demand Data

FIRM GAS SUPPLY AND DEMAND DATA (October 2015 - September 2016)

	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Total
Gas Supplies (MDTh)													
Beginning Inventory	69,851	74,217	71,914	66,566	50,018	38,909	35,474	32,492	39,396	47,553	53,750	60,441	
Natural Gas Receipt	14,339	13,022	12,874	19,391	18,370	15,231	10,481	15,364	12,805	10,297	10,706	10,874	163,753
Total Inventory Available	84,190	87,239	84,788	85,956	68,387	54,139	45,955	47,856	52,201	57,850	64,456	71,316	
Gas Demand (MDTh)													
Firm Sendout	9,973	15,325	18,222	35,939	29,478	18,666	13,463	8,460	4,648	4,100	4,014	4,213	166,502
Ending Inventory MDTh	74,217	71,914	66,566	50,018	38,909	35,474	32,492	39,396	47,553	53,750	60,441	67,103	

FIRM GAS SUPPLY AND DEMAND DATA (October 2016 - September 2017)

	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Total
Gas Supplies (MDTh)													
Beginning Inventory	67,103	71,216	72,093	61,442	44,701	31,826	18,750	24,172	33,601	44,025	53,695	62,237	
Natural Gas Receipt	13,415	18,706	21,010	16,046	12,544	16,742	16,112	16,911	15,266	13,595	12,636	11,137	184,119
Total Inventory Available	80,518	89,922	93,102	77,488	57,245	48,567	34,862	41,083	48,868	57,621	66,331	73,374	
Gas Demand (MDTh)													
Firm Sendout	9,302	17,829	31,660	32,788	25,419	29,817	10,690	7,481	4,842	3,926	4,093	4,342	182,190
Ending Inventory MDTh	71,216	72,093	61,442	44,701	31,826	18,750	24,172	33,601	44,025	53,695	62,237	69,032	

FIRM GAS SUPPLY AND DEMAND DATA (October 2017 - September 2018)

	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Total
Gas Supplies (MDTh)													
Beginning Inventory	69,032	76,094	71,634	61,028	49,251	39,341	24,392	22,454	33,924	41,976	51,066	56,490	
Natural Gas Receipt	13,910	16,355	24,624	28,007	15,893	14,558	16,237	18,502	13,327	13,028	9,232	12,235	195,908
Total Inventory Available	82,942	92,449	96,258	89,036	65,144	53,899	40,628	40,955	47,250	55,004	60,298	68,725	
Gas Demand (MDTh)													
Firm Sendout	6,848	20,815	35,229	39,785	25,803	29,507	18,175	7,032	5,274	3,938	3,808	4,032	200,247
Ending Inventory MDTh	76,094	71,634	61,028	49,251	39,341	24,392	22,454	33,924	41,976	51,066	56,490	64,693	

FIRM GAS SUPPLY AND DEMAND DATA (October 2018- September 2019)

	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Total
Gas Supplies (MDTh)													
Beginning Inventory	64,693	69,787	72,661	62,831	44,243	29,004	19,318	20,722	28,620	37,507	46,708	56,056	
Natural Gas Receipt	13,757	22,157	20,863	18,303	17,791	17,757	14,984	14,991	14,314	13,166	13,157	12,337	193,577
Total Inventory Available	78,450	91,944	93,524	81,134	62,034	46,761	34,302	35,713	42,935	50,673	59,865	68,393	
Gas Demand (MDTh)													
Firm Sendout	8,663	19,283	30,693	36,892	33,030	27,443	13,581	7,092	5,428	3,965	3,808	4,088	193,965
Ending Inventory MDTh	69,787	72,661	62,831	44,243	29,004	19,318	20,722	28,620	37,507	46,708	56,056	64,305	

Item 14
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FIRM GAS SUPPLY AND DEMAND DATA (October 2019- September 2020)

	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Total
Gas Supplies (MDTh)													
Beginning Inventory	64,305	69,788	71,542	60,217	43,698	29,125	20,541	20,942	28,659	37,191	46,038	55,001	
Natural Gas Receipt	14,203	21,442	19,864	19,086	18,477	18,278	13,995	14,888	14,006	12,786	12,817	12,001	191,843
Total Inventory Available	78,508	91,230	91,406	79,303	62,176	47,403	34,536	35,830	42,665	49,977	58,855	67,001	
Gas Demand (MDTh)													
Firm Sendout	8,720	19,688	31,190	35,605	33,051	26,862	13,594	7,171	5,474	3,939	3,854	4,141	193,288
Ending Inventory MDTh	69,788	71,542	60,217	43,698	29,125	20,541	20,942	28,659	37,191	46,038	55,001	62,861	

15. Actual Peak Day Supply and Demand

Actual Peak Day Supply and Demand - Item 15

		NEWARK AVG.	LOAD (000 DTh)			SUPPLY SOURCES (000 DTh)		
						NATURAL GAS		LPA / REFINERY /
	DATE	TEMP (F)	TOTAL	FIRM	INTERR.	HLF TRANSP.	STORAGE / LNG	LANDFILL
2017 / 2018 WINTER								
	6-Jan-18	8.8	2604	2556	48	1656	922	26
	31-Dec-17	11.1	2596	2424	173	1791	805	0
	5-Jan-18	11.9	2527	2499	28	1734	779	14
	1-Jan-18	15.7	2505	2350	155	1851	654	0
	28-Dec-17	15.3	2502	2281	220	1987	514	0
2016 / 2017 WINTER								
	15-Mar-17	25.7	2538	1878	660	1581	940	17
	9-Jan-17	20.1	2501	2156	345	1357	1132	13
	14-Mar-17	25.4	2479	1810	669	1626	834	18
	8-Jan-17	18.5	2456	2133	323	1332	1112	12
	4-Mar-17	21.9	2383	1906	477	1206	1160	17
2015 / 2016 WINTER								
	13-Feb-16	9.7	2713	2423	290	1689	990	34
	14-Feb-16	14.6	2608	2325	283	1649	942	17
	18-Jan-16	20.5	2594	2071	523	1822	770	2
	4-Jan-16	18.9	2591	1981	610	1814	773	4
	11-Feb-16	20.7	2574	2058	515	1776	782	16

16. Capacity Contract Changes

Including Gas Forecast Support

May 2018

PEAK DAY GAS REQUIREMENTS AND SUPPLY
(MDTh)

	SUPPLY		2018-19	2019-20	2020-21	2021-22	2022-23
	Transco FT		432.4	432.4	432.4	432.4	432.4
	Transco FT (DTI)		32.2	32.2	32.2	32.2	32.2
	Transco FT (Cove Point)		20.0	20.0	20.0	20.0	20.0
	Texas Eastern FT		233.0	233.0	233.0	233.0	233.0
	Tennessee FT		36.4	36.4	36.4	36.4	36.4
	FT from Lebanon:						
	Texas Eastern		180.7	180.7	180.7	180.7	180.7
	DTI/Transco		49.7	49.7	49.7	49.7	49.7
	Columbia		12.5	12.5	12.5	12.5	12.5
	Subtotal		242.9	242.9	242.9	242.9	242.9
	Transco/Tetco FT (Leidy)		330.3	330.3	330.3	330.3	330.3
	Columbia (Hanover)		12.5	12.5	12.5	12.5	12.5
	Pipeline Firm Transportation		1,339.6	1,339.6	1,339.6	1,339.6	1,339.6
	Refinery Gas		0.0	0.0	0.0	0.0	0.0
	Total Firm FT Supply		1,339.6	1,339.6	1,339.6	1,339.6	1,339.6
	Storage		900.7	900.7	900.7	900.7	900.7
	Transco Peaking		13.2	13.2	13.2	13.2	13.2
	Transco LGA		275.4	275.4	275.4	275.4	275.4
	PSEG Burlington LNG		67.4	67.4	67.4	67.4	67.4
	LPA		197.4	197.4	197.4	197.4	197.4
	Total Peaking Supply		553.4	553.4	553.4	553.4	553.4
	PSEG Firm Supply Subtotal		2,793.8	2,793.8	2,793.8	2,793.8	2,793.8
	FTS DCQ 1./		255.3	285.3	256.5	287.8	260.2
[a]	Total PSEG Gas Supply		3,049.1	3,079.1	3,050.3	3,081.6	3,054.0
	Peak Day Sendout Forecast 2./		2,936.4	2,938.1	2,958.8	2,978.6	3,034.0
[b]	Total Peak Day Capacity Requirements	3./	3,103.2	3,104.6	3,127.1	3,159.7	3,220.9
[a]-[b]	Surplus / (Deficiency)	3./	(54.2)	(25.5)	(76.9)	(78.1)	(166.9)

1./ Forecasted FT-S DCQ (January)
2./ Based on Corporate Energy Forecast, Gas -2018
3./ 3% Loss of Load Probability

Natural Gas Sales Forecast - 2018

Public Service Electric & Gas Company

Finance Department

Electric and Gas Sales and Revenue Forecasting Group

April 2018

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Introduction

The natural gas sales forecast has a key role in both the operating and financial planning processes of Public Service Electric & Gas (PSE&G).

The volumetric and maximum day sendout projections are used in the development of strategies for optimal gas procurement by PSE&G's BGSS supplier.

The sales forecast also serves as the basis for the natural gas revenue forecast that is a key parameter in PSE&G's financial planning process. This includes not only the budgeting process but also the regulatory process.

The purpose of this document is to describe the current forecast methodology, forecast assumptions, and the 2018 gas sales forecast. The first section describes the econometric sales models. A discussion of the forecast assumptions used to develop the sales forecast follows. Section III describes the maximum daily send-out projection. An appendix contains more detailed information on the billing period to calendar month conversion, and forecast tables.

I Model Specification and Estimation

Residential Model

Residential gas sales are determined by the number of residential customers and the amount of gas that each of these customers uses. As a result, the modeling of residential sales is disaggregated into two components: the projection of the number of customers and the estimate of what, on average, each of these customers will use. While the projection of the number of residential natural gas customers can be based on historical trends and expected residential construction activity in the service area, the models utilized to develop the average use forecast are more complicated and are described below.

The demand for energy is a derived demand from the demand for the services that the energy provides. In the case of gas in the residential sector, this is a demand for the three main end-uses of gas: space heating, water heating, and cooking. Standard microeconomic theory suggests that the demand for these gas-fueled end-uses is a function of the real, i.e. inflation adjusted, price of gas, and the income of the household. In addition, since space heating and, to a lesser extent, water heating are affected by the weather, weather also needs to be included in the model specification, i.e.

$$\text{THERM/CUST} = f(\text{PRICEGAS, INCOME, WEATHER}) \qquad [1]$$

where:

THERM/CUST	= Average gas sales per customer,
PRICEGAS	= Real price of gas,
INCOME	= Measure of customer income,
WEATHER	= Billing-month weather.

While information on individual appliance ownership and consumption is not available, PSE&G does segregate its Residential customer data into those customers that have gas space heating and those that do not. As a result, separate models estimating the average gas sales for space heating customers and non-space heating customers were developed.

Weather is incorporated into the models using billing-month heating degree days (HDD). To allow for the possibility of month-specific response to weather, the heating degree data was multiplied by monthly binary variables to produce month-specific HDD independent variables.

The real price of gas was defined as the annual average revenue per therm divided by the Consumers' Price Index –All Urban Consumers. However, the extreme seasonality of monthly gas consumption made the utilization of this variable directly in a linear specification impractical because it is unrealistic to expect that a change in price would have the same impact, measured in therms, in January, a high consumption month, as in July where consumption can be only one-tenth the January volume. As a result, this variable was incorporated as an interactive variable with HDD to create the effect that a change in price will affect the magnitude of the response to weather, i.e. a small response in the summer months and a much larger response during the space heating season.

Income is defined as the total real wages and salary disbursements for New Jersey from the U.S. Department of Commerce, Bureau of Economic Analysis. This is a narrower measure than personal income, omitting for example dividends, interest and rental income, and, as a result, is assumed to more accurately reflect the economic well-being of the majority of our customers. The incorporation of this variable directly into a linear specification suffers from the same drawback as that of the price. As a result, this variable was also incorporated into the specification as an interactive variable with HDD. In the models the economic variables were lagged one year to account for the delay in the impact that these variables have on consumer behavior.

As a result, the final functional form of the model that was estimated is:

$$THERM/CUST_t = f(\overline{MONTH}xHDD_t \times PRICEGAS_{a-1}, \overline{MONTH}xHDD_t \times INCOME_{a-1}, \overline{MONTH}xHDD_t) \qquad [2]$$

where:

THERM/CUST	= Average gas sales per customer,
PRICEGAS	= Real price of gas,
INCOME	= Real Wage and Salary Disbursements,
HDD	= Heating degree days,
$\overline{MONTH}$	= Vector of binary variables for each heating month,
t	= Billing-month,
a	= Year associated with billing-month, t.

The models were estimated using monthly data from the 2006-2016 period (excluding data from 2009 due to distortions resulting from the implementation of a new billing system.)The results of the OLS estimation procedure are summarized in Table 1 and Figures 1 and 2.

As Figures 1 and 2 illustrate, the high values of the coefficients of determination of both the model for gas space heating customers and the model of those customers without gas heating explain an extremely high proportion of the variation from the mean values. The estimates of the individual coefficients of the RSG model estimations are what one would expect given the characteristics of residential natural gas consumption. The key predictor of gas sales to this sector is weather with the weather having a greater impact on those customers with gas space heating than those without. Price is a factor for residential customers during the winter months but, it's impact is relatively small.

Figure 1
RSG Space Heating Model
Actual vs. Fitted Values

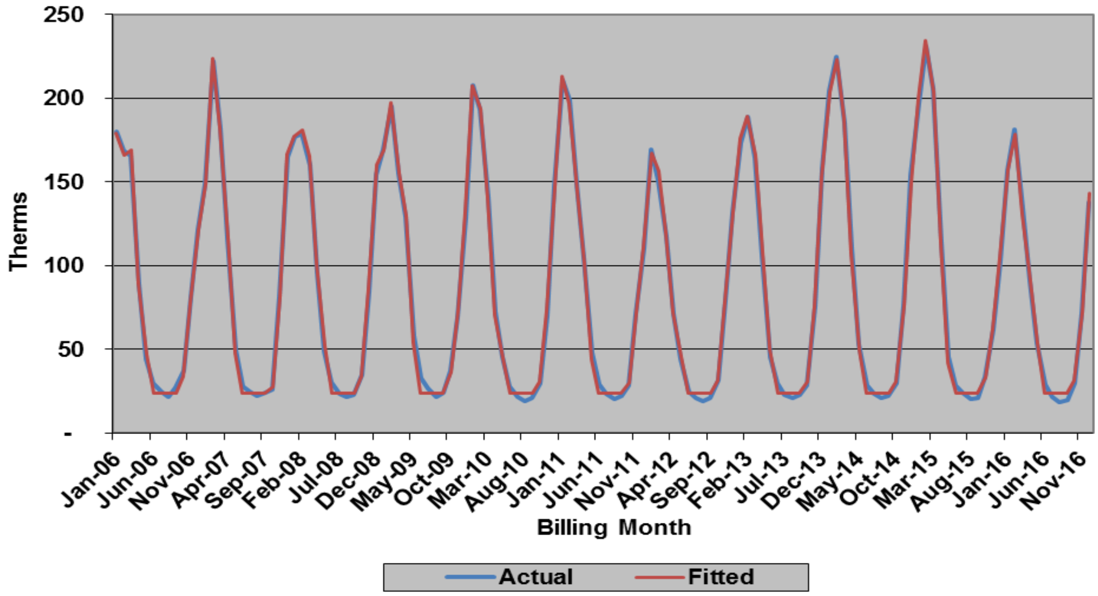
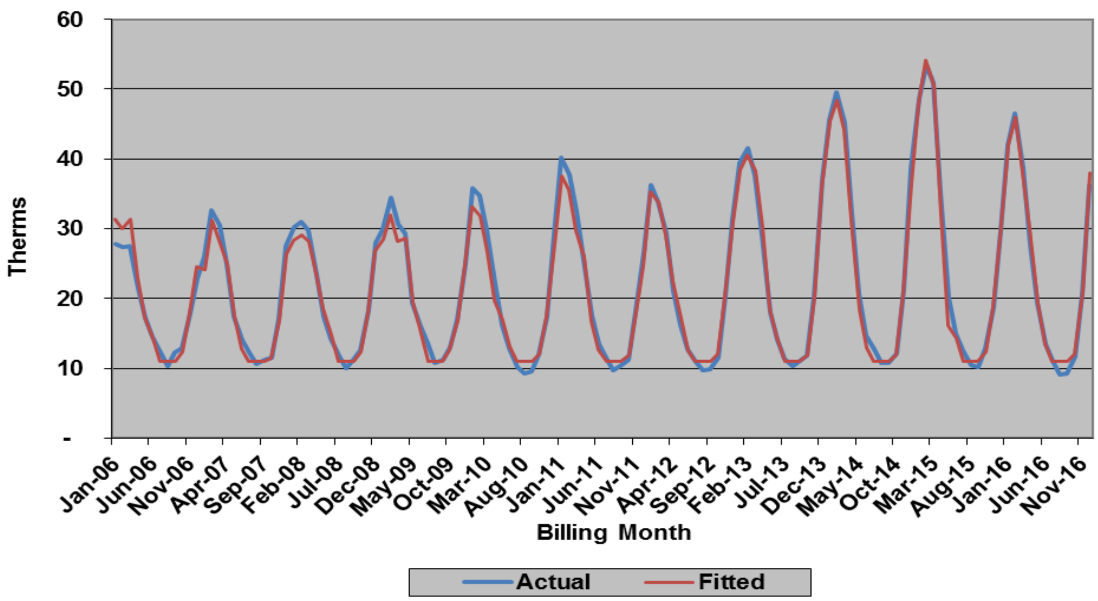


Figure 2
RSG Non-Space Heating Model
Actual vs. Fitted Values



The price elasticity estimates were estimated to be -0.0038 and -0.23 for space heating and non-space heating customers, respectively which is lower than recent estimates but consistent with lower gas prices and the lack of a surge in consumption in response to them. The higher non-space heating elasticity is the result of a similar therm impact of price but, measured over a much smaller base usage. Income was found to have an effect on gas consumption by space heating customers in the fall. This is consistent with income changes resulting affecting when space heating equipment is turned on. The economic downturn appeared to result in a delay in turning on this equipment in the fall reducing use.

Table 1

Estimated Coefficients of the Residential Models

(standard errors in parentheses)

	JAN	FEB	MAR	APR	MAY	JUNE	OCT	NOV	DEC	R2	DW	n
HEATING												
HDD	0.19548	0.20422	0.20099	0.18334	0.12795					0.998	1.414	132
	(0.009)	(0.009)	(0.007)	(0.013)	(0.005)							
PRICE x HDD		-0.00195							-0.00500			
		(0.003)							(0.005)			
WAGE x HDD							0.001256	0.002360	0.002880			
							(0.0002)	(0.0000)	(0.0001)			
I-POWER	-0.00595											
	(0.001)											
NON-HEATING												
HDD	0.05586	0.05553	0.05907	0.05737	0.03430	0.06980	0.01024	0.03901	0.05284	0.973	0.638	132
	(0.0029)	(0.0025)	(0.0031)	(0.0053)	(0.0033)	(0.0151)	(0.0065)	(0.0072)	(0.0036)			
PRICE x HDD	-0.020	-0.020	-0.021	-0.017				-0.013	-0.018			
	(0.0020)	(0.0017)	(0.0021)	(0.0036)				(0.0048)	(0.0024)			

The second key element of the residential forecast, as noted above, is the projection of the number of residential natural gas customers. This forecast is based on historical trends between customer growth and residential construction activity in the service area and is discussed in the Forecast Assumptions section.

Commercial

The demand for natural gas by the non-residential sector, as with any other factor of production, is a function of the input's price, the price of substitutes (if any) and the level of production. This implies that gas sales to the commercial sector is a function of the real price of gas and the level of "output" of the commercial sector in PSE&G's service territory, i.e. Again, since gas is primarily used for space and/or water heating, weather needs to be included in the specification resulting in the following:

THERMS = *f*(PRICEGAS, OUTPUT, HDD) [3]

where:

THERMS	= Gas Sales,
PRICEGAS	= Real price of gas,
OUTPUT	= Commercial sector output,
HDD	= Heating degree days.

The problem with this specification is that there is not a good measure of output for the local commercial sector. However, if it is assumed that the demand for local commercial output is a function of the local economic and demographic factors, i.e., how many households there are (HSH) and how much money do they have to spend (INCOME), commercial output can then be defined as:

OUTPUT = *f*(INCOME, HSH) [4]

Substituting [4] into [3] yields:

THERMS = *f*(PRICEGAS, INCOME, HSH, HDD) [5]

This model was estimated for customers in the commercial sector using monthly billing data from the 2005-2016 period (again, excluding 2009). The firm delivery customers in this class whose usage does not exceed 300 Dth are served under rate GSG. These customers are further disaggregated into those with gas space heat and those that heat with other fuels. These two groups of customers are modeled separately. The larger commercial customers are served under rate LVG. These are also modeled separately.

Historical annual household estimates for New Jersey is available from the U.S. Bureau of the Census. As with the residential models, the strong seasonality associated with commercial gas sales dictates that the economic/demographic variables can be used in the model directly but, need to be used as interactive variables with HDD. In addition, in the models the economic variables were lagged one year to account for the delay in the impact that these variables have on consumer behavior. As a result, the functional form that was estimated for each of the three groups of commercial customers is[1]:

$$\begin{aligned} THERMS_t = f(&\overline{MONTH} \times HDD_t \times PRICEGAS_{a-1}, \\ &\overline{MONTH} \times HDD_t \times INCOME_{a-1}, \\ &\overline{MONTH} \times HDD_t \times HSH_{a-1}, HDD_t) \end{aligned} \qquad [6]$$

where:

THERMS	= Gas sales,
PRICEGAS	= Real price of gas,
INCOME	= Real Wage and Salary Disbursements,
HDD	= Heating degree days,
$\overline{MONTH}$	= Vector of binary variables for each heating month,
t	= Billing-month,
a	= Year associated with billing-month, t.

The results of the OLS estimation procedure, summarized in Figures 3-5, show that the commercial models also fit the historical data well.

The estimated coefficients of the three commercial models indicate that while the small commercial space heating are sensitive to price, with an estimated elasticity of -0.10 the non-space heating customers and the large LVG, customers are not. In addition, while the coefficients on households, the economic indicator in the models, are highly statistically significant, this does not imply large sales increases given the anticipated slow growth in the number of households.

[1] It was not necessary to incorporate month-specific HDD specification since the LVG sales are less sensitive to the weather.

Figure 3
GSG Commercial Space Heating Model
Actual vs. Fitted Values

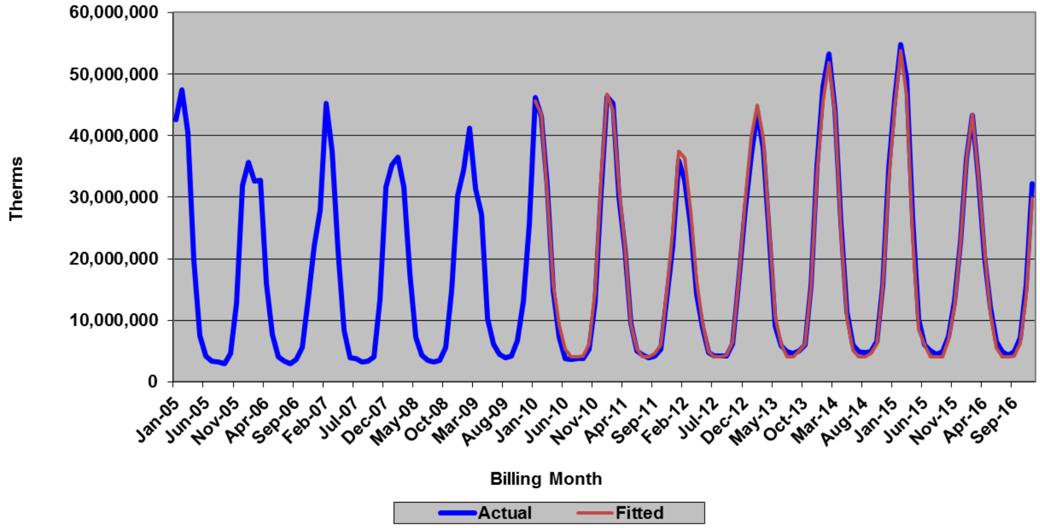


Figure 4
GSG Commercial Non-Space Heating Model
Actual vs. Fitted Values

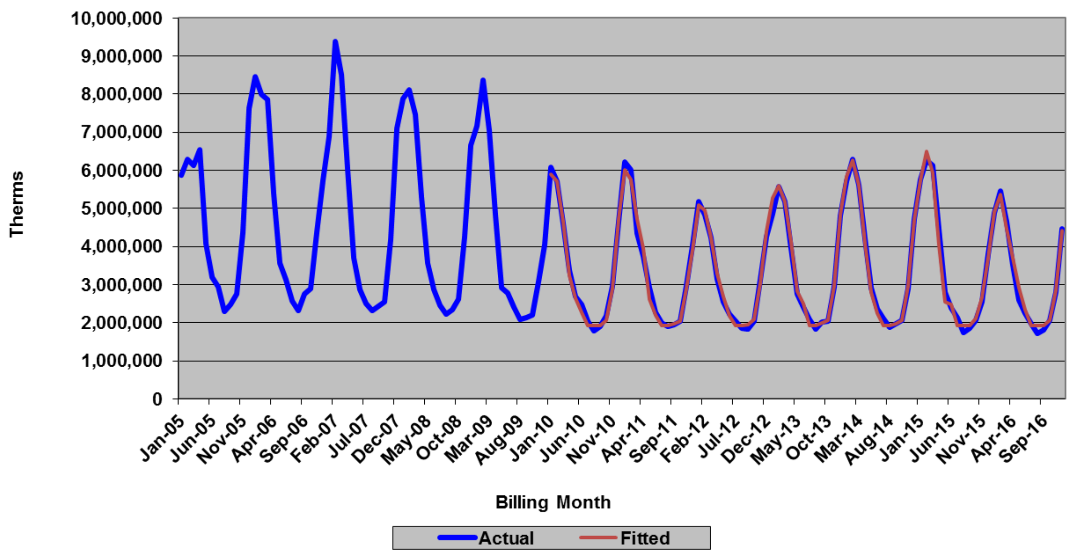


Figure 5
LVG Commercial Model
Actual vs. Fitted Values

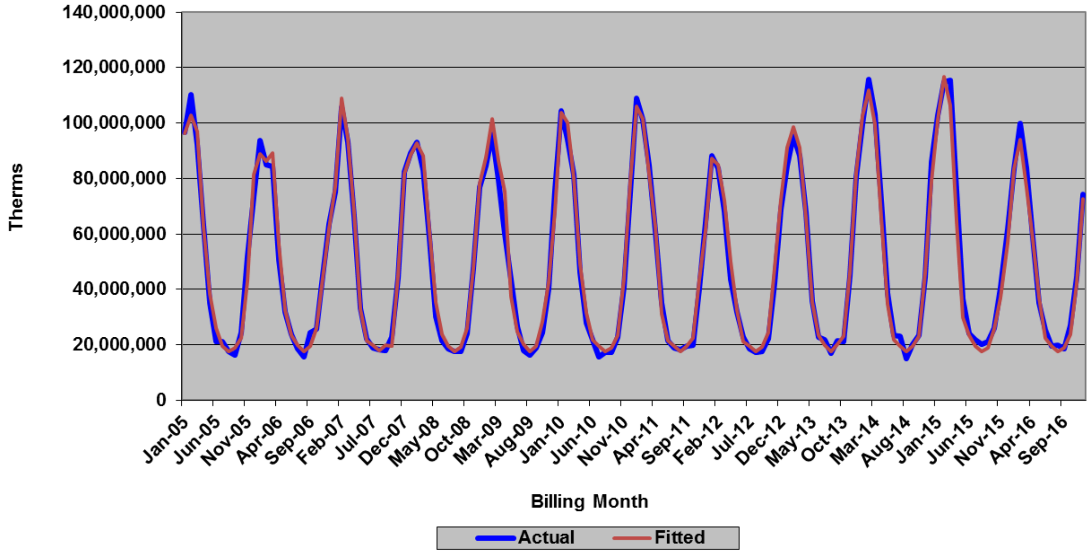


Table 2

Estimated Coefficients of the GSG Commercial Gas Sales Models
(standard errors in parentheses)

	JAN	FEB	MAR	APR	MAY	JUN	SEP	OCT	NOV	DEC	R2	DW	n
HEATING													
PRICE x HDD	-2487	-10618	-19025	-12154							0.994	0.588	84
	(4,933)	(4,840)	(6,625)	(10,390)									
CUST x HDD	13.29	16.65	19.27	15.68	9.15	12.34	14.70	6.73	8.88	11.29			
	(1.68)	(1.62)	(2.20)	(3.42)	(0.98)	(5.37)	(19.64)	(1.88)	(0.51)	(0.27)			
NON-HEATING													
HDD	3791	3897	3978	4066	4128	11551	3328	1382	2623	3518	0.990	1.662	84
	(70.75)	(68.73)	(86.63)	(145.79)	(348.09)	(1,916.59)	(7,055.80)	(674.98)	(182.33)	(95.69)			

Table 3

Estimated Coefficients of the LVG Commercial Gas Sales Models

(standard errors in parentheses)

	HDD x CUST	R2	DW	n
CUST x HDD	24.44	0.989	1.549	132
	(1.28)			

Industrial

While gas sales to the commercial sector are correlated with commercial output because output tends to be correlated with commercial space-heated floor space, sales to the PSE&G rate GSG and rate LVG gas customers in the industrial sector are not correlated with the industrial output because gas, for the most part, is not used for process heat. It is used to heat employee workspaces and the number of employees has been declining while industrial output has been increasing. Therefore, rather than used the traditional function for the demand for a factor of production such as [3], the following specification is used:

$$\text{THERMS} = f(\text{PRICEGAS, EMP, HDD}) \qquad [7]$$

where:

EMP = Manufacturing employment.

Since gas is used primarily for space heating the economic variables need to be used as interactive variables with HDD to account for the extreme seasonality of the data. As a result, the functional forma that was estimated is:

$$\text{THERMS}_t = f(\text{HDD}_t \times \text{PRICEGAS}_{a\text{-}1}, \text{HDD}_t \times \text{EMP}_{a\text{-}1}, \text{HDD}_t) \qquad [8]$$

where:

THERMS	= Gas sales,
PRICEGAS	= Real price of gas,
HDD	= Heating degree days,
t	= Billing-month,
a	= Year associated with billing-month, t.

The results of the OLS estimation procedure, summarized in Figures 6-8, show that the industrial models for customers in the two space heating segments fit the historical data well. The data for industrial GSG non-heating customers, however, seems to indicate the presence of out of period adjustments in the billing data which the model doesn't, and can't be expected to, account for. These were addressed with binary variables.

Like the small and medium commercial models, the estimated coefficients of the three industrial models indicate that sensitivity to price is small. The small industrial customers, rate GSG & LVG, did not show any statistically significant response to price. Small response of the industrial sector to gas prices is attributed to the fact that gas, since it is not used for process heat, is a relatively small proportion of the total costs of production.

Figure 6

GSG Industrial Space Heating Model

Actual vs. Fitted Values

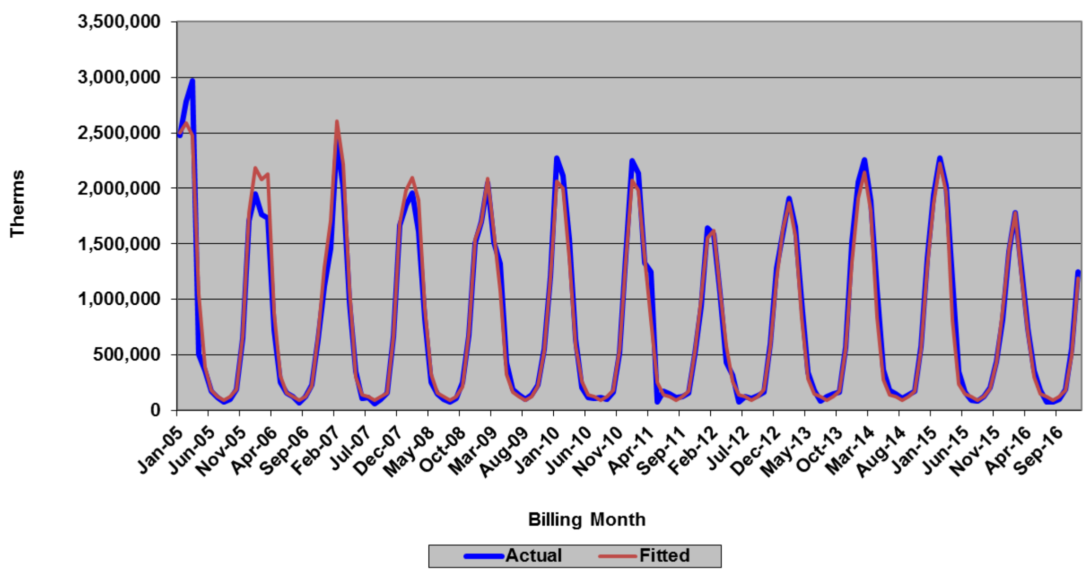


Figure 7
GSG Industrial Non-Space Heating Model
Actual vs. Fitted Values

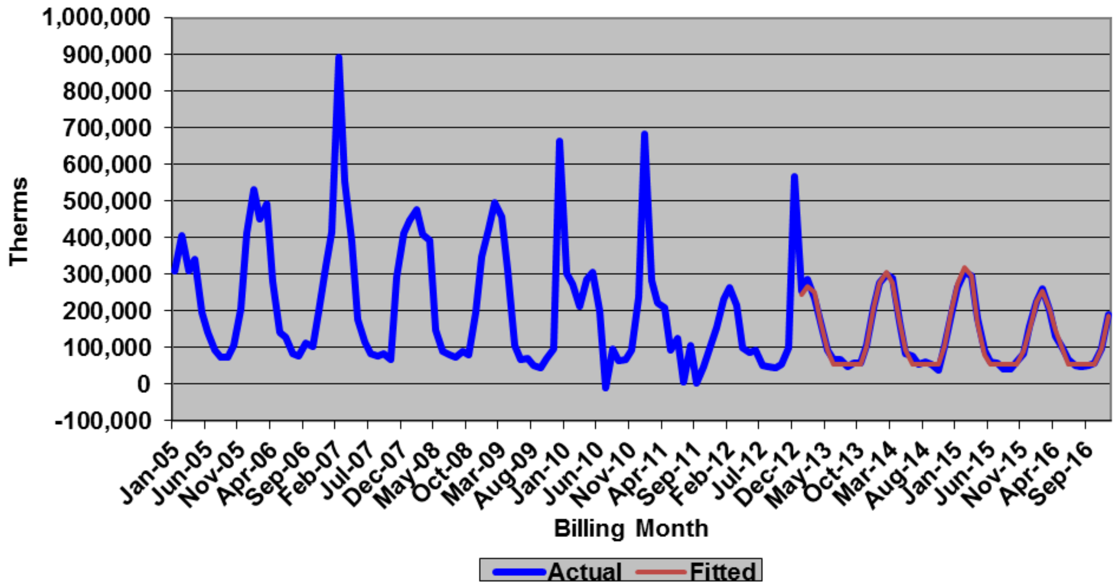


Figure 8
LVG Industrial Heating Model
Actual vs. Fitted Values

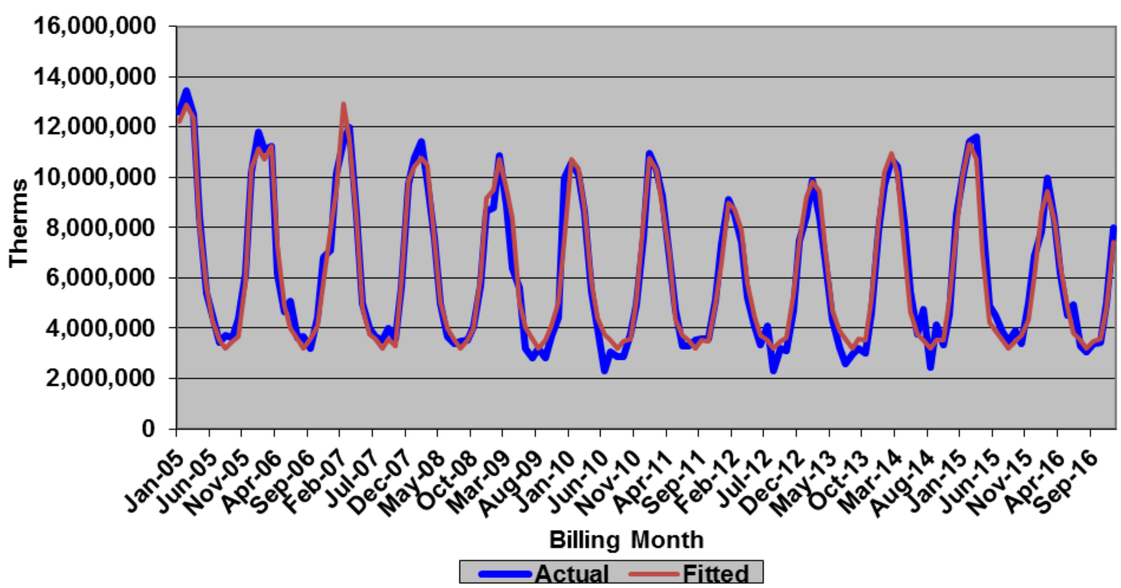


Table 4

Estimated Coefficients of the GSG Industrial Gas Sales Models

(standard errors in parentheses)

	JAN	FEB	MAR	APR	MAY	JUN	OCT	NOV	DEC	R2	DW	n
HEATING												
EMP x HDD	8.15 (1.11)	6.59 (0.91)	8.73 (0.81)	5.55 (0.36)	3.04 (0.85)	2.15 (3.64)	2.29 (1.69)	4.48 (0.46)	5.70 (0.90)	0.974	1.482	132
NON-HEATING												
HDD	215.05 (5.79)	224.93 (5.21)	237.31 (6.26)	211.63 (10.59)	173.23 (25.85)			117.62 (14.99)	184.92 (7.51)	0.990	1.881	48

Table 5

Estimated Coefficients of the LVG Industrial Gas Sales Models

(standard errors in parentheses)

HDD x EMP	R2	DW	n
27.98 (1.77)	0.968	1.751	132

II Forecast Assumptions

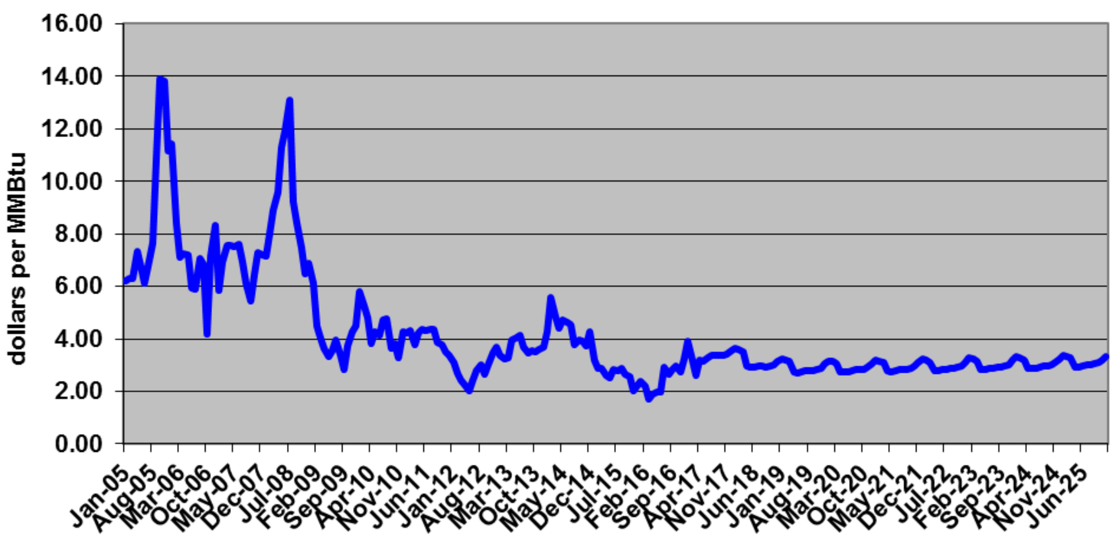
The models described above, in concert with assumptions about future prices and local economic and demographic parameters, were utilized to produce a forecast of billed natural gas delivered sales by rate for the residential, commercial, and industrial customer classes. The assumptions and the forecasts are described in more detail below.

Natural Gas Prices

The main driver of retail natural gas prices is the wholesale cost of gas which changes monthly. While these costs are passed through to commercial and industrial customers on monthly basis, the gas cost under- or over-collection of the residential customers is addressed in October where the rate is adjusted to collect or return the imbalance over the following twelve months. For the purpose of the forecast, the wholesale natural gas price was assumed to follow the NYMEX future prices as of April 20, 2016. As figure 9 shows, the wholesale price of gas is projected to stay relatively stable during the 2015-2021 periods.

Figure 9

NYMEX Natural Gas Futures Prices, April 28, 2017
($/MMBtu)



This price projection was used in the ER&T Gas cost model which generated commodity gas costs by rate. The residential costs, along with the actual imbalance in the residential gas supply cost and the revenue collection to offset this cost was utilized in the Cognos residential model to produce a stream of residential prices assuming that every October the imbalance was trued-up over the following 12 months. These projected commodity costs, combined with delivery tariff assumptions results in projected retail prices that are summarized below.

Table 6

Historic and Projected Retail Gas Prices

(dollars per therm)

			Commercial			Industrial		
	RSG		GSG			GSG		
Year	Heating	Non-Heating	Heating	Non-Heating	LVG	Heating	Non-Heating	LVG
2005	1.13	1.31	1.37	1.38	1.24	1.37	1.37	1.21
2006	1.39	1.58	1.41	1.30	1.23	1.43	1.33	1.22
2007	1.35	1.54	1.31	1.27	1.17	1.32	1.24	1.13
2008	1.40	1.57	1.42	1.42	1.29	1.41	1.40	1.25
2009	1.40	1.56	1.09	1.05	0.94	1.09	1.06	0.92
2010	1.24	1.43	1.10	1.07	0.97	1.11	1.06	0.92
2011	1.09	1.26	1.06	1.04	0.92	1.05	1.05	0.87
2012	1.00	1.18	0.95	0.93	0.80	0.95	0.98	0.75
2013	0.94	1.09	1.00	0.99	0.84	1.00	1.01	0.80
2014	0.80	0.94	1.06	1.04	0.91	1.10	1.08	0.90
2015	0.64	0.80	0.86	0.85	0.74	0.86	0.88	0.74
2016	0.71	0.87	0.83	0.83	0.69	0.83	0.86	0.70
2017	0.70	0.86	0.88	0.88	0.73	0.88	0.91	0.74
2018	0.73	0.89	0.87	0.87	0.72	0.87	0.90	0.74
2019	0.74	0.89	0.86	0.86	0.70	0.86	0.89	0.71
2020	0.74	0.89	0.86	0.86	0.70	0.86	0.89	0.71
2021	0.75	0.90	0.86	0.86	0.70	0.86	0.89	0.71
2022	0.78	0.94	0.87	0.87	0.71	0.87	0.90	0.72
2023	0.85	1.00	0.87	0.87	0.71	0.87	0.89	0.72
2024	0.74	0.89	0.64	0.65	0.49	0.64	0.67	0.49
2025	0.74	0.89	0.64	0.65	0.49	0.64	0.67	0.49

Economic Projections

Economic and demographic forecast assumptions for the nation and New Jersey are from Global Insight's March 2016 forecast. This forecast assumes that, nationally, the economy continues to recover at a slow but steady rate. This national forecast is expected to be reflected in New Jersey's economic outlook that is also expected to be at a slow pace. The forecast is summarized in Table 7.

Weather during the forecast period is assumed to be "normal" as defined by the average daily weather during the twenty-year period ending December 31, 2015.

Table 7

National and New Jersey Economic Forecast Assumptions

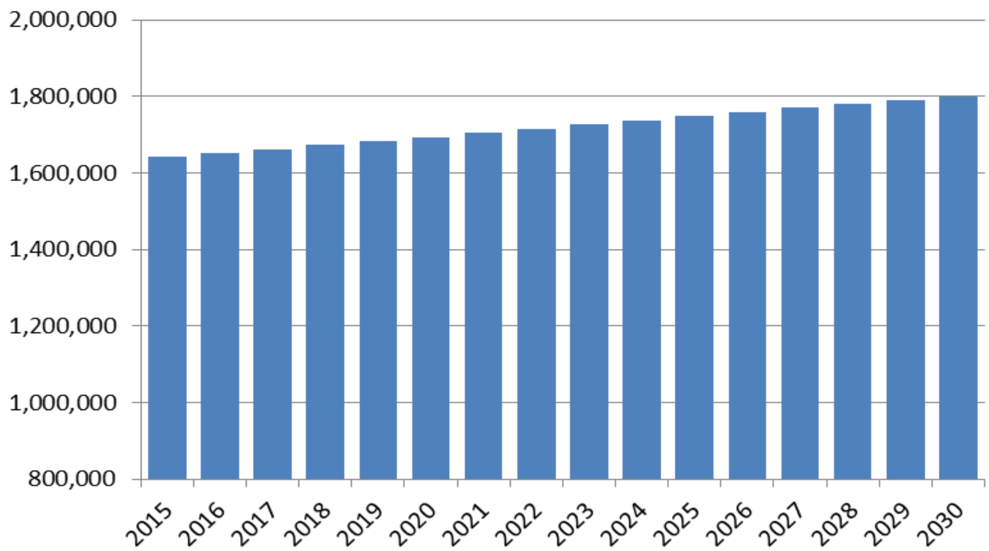
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
United States												
Real Gross Domestic Product (Bil-$)	15,982	16,397	16,660	17,039	17,482	17,876	18,276	18,683	19,085	19,479	19,862	20,250
Industrial Production (%,saar)	2.9	0.3	(0.9)	1.9	2.9	2.2	2.2	2.0	1.7	1.6	1.3	1.2
Personal Income (%,saar)	5.2	4.4	3.6	4.5	5.1	5.2	5.0	4.8	4.8	4.8	4.7	4.7
Payroll Employment (%,saar)	1.9	2.1	1.8	1.6	1.3	1.0	0.9	0.7	0.8	0.8	0.7	0.7
Unemployment Rate (%)	6.2	5.3	4.9	4.6	4.2	4.1	4.2	4.3	4.4	4.4	4.5	4.5
Consumers' Price Index(%, AAR)	1.6	0.1	1.3	2.5	1.9	2.4	2.8	2.7	2.7	2.7	2.6	2.6
3-Month Treasury Bill Rate (%)	0.0	0.1	0.3	0.9	1.6	2.5	2.8	2.8	2.8	2.8	2.8	2.8
30-Year Fixed Mortgage Rate (%)	4.2	3.9	3.6	4.5	5.0	5.8	6.1	6.1	6.1	6.1	6.1	6.1
New Jersey												
Real Personal Income (mil-$)	413,465	428,599	438,093	449,582	464,239	476,423	486,353	495,792	505,799	515,709	525,507	535,241
Total Employment (thous SA)	3,968	4,023	4,076	4,109	4,144	4,167	4,181	4,194	4,212	4,228	4,240	4,251
Manufacturing (thous. SA)	239	238	240	241	241	241	240	238	237	235	233	231
Nonmanufacturing (thous. SA)	3,729	3,785	3,835	3,868	3,903	3,926	3,941	3,956	3,975	3,993	4,007	4,020
Unemployment Rate (% SA)	6.7	5.6	4.9	4.6	4.3	4.1	4.2	4.2	4.3	4.4	4.5	4.5
Population (thous.)	8,925.3	8,936.5	8,946.0	8,959.8	8,980.6	9,007.9	9,039.1	9,070.7	9,102.0	9,132.7	9,162.7	9,191.8
Households (thous.)	3,234.1	3,233.4	3,244.4	3,252.5	3,270.8	3,294.6	3,316.4	3,337.4	3,358.8	3,379.9	3,399.9	3,420.0
Single-Family Housing Starts (thous.)	10.5	10.9	10.9	11.6	11.6	12.0	12.3	12.7	12.7	12.7	12.9	12.4

Customer Forecasts

The number of residential customers with and without natural gas space heat is based on historical trends and expected residential construction activity in the service area. Residential non-heating customers have been steadily declining at an average annual rate of 0.8 percent and this is expected to continue. Furthermore it is assumed that these customers are converting to gas heat. The number of gas heating customers is also expected to increase as new residential construction occurs. The number of gas customers is assumed to reflect the current decline seen in new single family housing construction. As a result, as the figure below shows, the number of residential customers is expected to remain relatively stable.

Figure 10

Annual Gas Residential Customers



BGSS Share

The share of delivered sales that are BGSS supplied is assumed to follow recent trends where therm shares have stabilized at their current levels across the broad range of customer classes.

III Maximum Daily Sendout Forecast

Introduction

Distribution facilities are designed to meet the estimated maximum hour demand on a day with a mean temperature of 0°F and an assumed average wind velocity of 15 m.p.h. with Newark Airport as the measuring base. Gas supplies are designed to meet the estimated maximum daily as well as maximum hourly demand. The maximum daily sendout forecast process consists of:

- Estimating the relationship between weather and firm daily sendout,
- Extrapolating that relationship to determine the current level of daily sendout at 0 degrees if no day that cold appeared in the model estimation data,
- Forecasting future maximum daily sendout levels based on the current estimated level

The remainder of this section describes each of these steps in turn.

Daily Firm Sendout Model Estimation

There are two major issues in modeling maximum firm daily sendout. First, the diversity of the customer base needs to be controlled for. Second, the model has to be designed to be extrapolated rather than interpolated. Each of these issues is discussed below.

The firm sendout number accounts for gas deliveries to a diverse set of customers ranging from residential homes to large industrial sites. Since sales to different types of customers respond to weather differently, customer mix must be controlled for in any modeling effort. In addition, the behavior of this diverse group of customers will change differently over time as prices and other economic parameters change over time. As a result, these changes also need to be accounted for. Unfortunately, the firm sendout number is not available by rate. As a result, the only way to control for changes in customer mix and changes in the behavior over time by these customers is to limit the time period of data that is used in the model estimation.

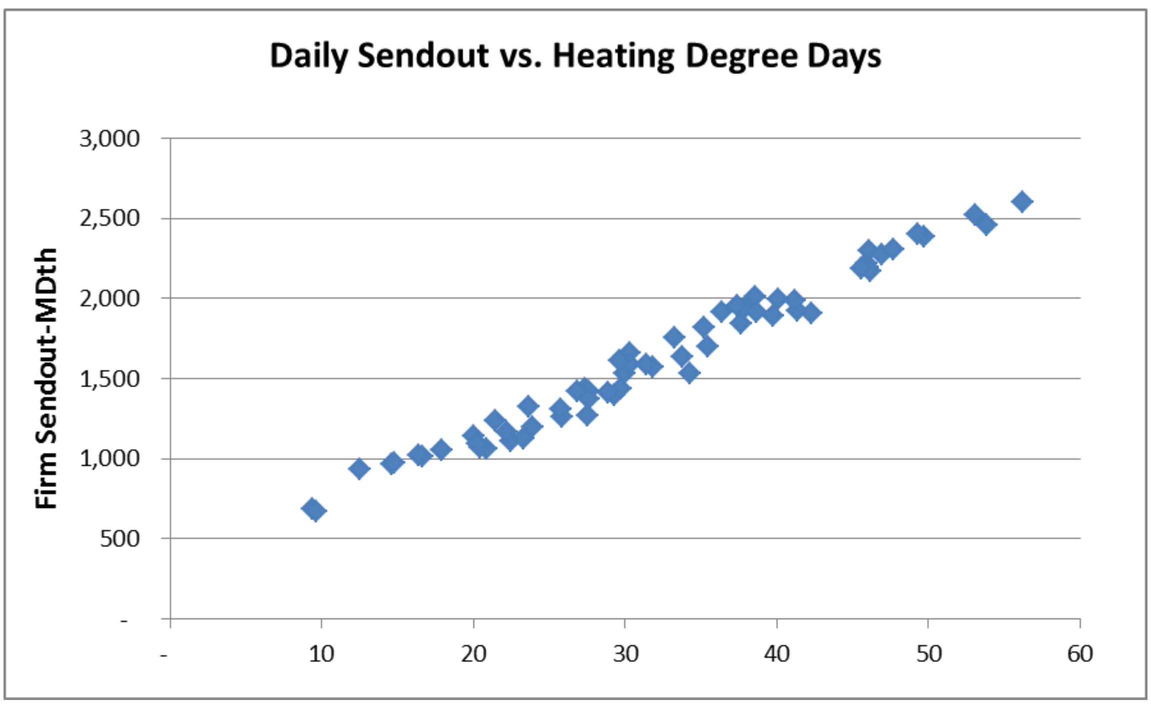
The second issue, of extrapolation, is addressed in a similar way. The relationship between sendout and weather is fairly linear. In reality, it is probably not perfectly linear. This is not an issue when estimating a model and using the results to interpolate values with the range of the estimation data. However, when extrapolating the data outside the range of the estimation data the imprecision increases. The way to minimize this imprecision is to limit the observations to the lower temperature data so as to get a linear estimation of that portion of a non-linear curve that is closest to the ultimate extrapolation value.

To address both of these forecasting issues, the data used in estimating the relationship between daily sendout and weather was limited to the months of December 2018 and January 2018. Customer class mix will not change significantly in this short period and it contains the two coldest months when the maximum sendout would most likely occur. Analysis of the data for these two months indicates two things.

First, the data confirms the general responsiveness of firm sendout to the weather, as Figure 11 shows. Second, the relationship appears linear

Figure 11

December 2017 and January 2018



To refine the impact of the day-type on sendout, the regression model from previous years was enhanced to allow for not only an intercept change from the day-type but, also a HDD response change.

The regression model that modeled daily sendout, SENDOUT, is specified as:

$$SENDOUT_t = f(HDD_t, WEEKDAY_t, HOLIDAY_t, SNOW_t) \qquad [9]$$

Where:

HDD	=	Heating degree days on gas day t,
WEEKDAY	=	Interactive variable that takes the value of HDD on weekdays, otherwise 0,
HOLIDAY	=	Interactive variable that takes the value of HDD on Sundays or Holidays, otherwise 0,
SNOW	=	Binary variable that takes the value of 1 when reported snowstorm accumulation in any portion of the service area is 6 inches or more, 0 otherwise.

The estimation results are shown in Table 8 and Figure 12 below.

Table 8

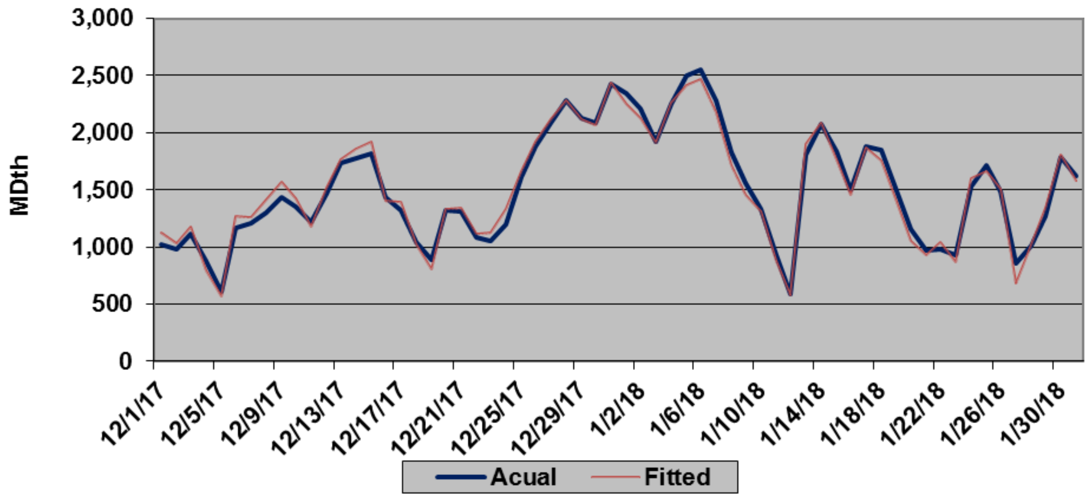
Estimated Coefficients of the Daily Sendout Model

(standard errors in parentheses)

Intercept	HDD	HOLIDAY	WEEKDAY	SNOW	R2	DW	n
175.30	40.87	1.17	1.43	99.57	0.979	1.206	62
(28.23)	(1.04)	(.92)	(.80)	(54.98)			

Figure 12

Daily Sendout Model
Actual vs. Fitted Values



The estimated coefficients of the model suggest that he estimated maximum daily peak would occur on a weekday. The model predicts that the maximum peak daily sendout would be 2,924.6 MDth.

A. Calendar-Month Sales Calculation

Introduction

Utilities have traditionally had a disconnection in the timing of their revenues and their costs. Revenues from retail sales are a revenue stream from meter readings and the resulting bills to their customers that occur on a daily basis throughout the month. The bills issued from meter reads in the current month's meter reading schedule are all recorded as billing-month revenue. Billing-month revenue will include revenue from electricity or gas delivered during the previous month while excluding deliveries of electricity or gas delivered during the current month that occurred after the meters were read. Expenses, on the other hand, such as wages, fuel, depreciation, etc., have been recorded on a calendar-month basis. This inconsistency in the revenue and expense streams can be tolerated if there are no major changes in the revenue and/or expense streams. If major changes are occurring, such as a rapid increase in fossil fuel prices or a high seasonality in sales, a comparison of the billing-month revenue and the calendar-month expenses can give a false view of a utility's financials. To remedy this situation, the sales and revenue accrual calculation, the estimation of calendar-month sales and revenue from billed sales and revenue and the estimation of unbilled sales and revenue was developed.

Section II will discuss how, in theory, the billed sales and the unbilled estimates are used to calculate calendar-month sales using a simple example and introduce the notation that will serve as the basis of the analysis. A description of the theory's specific application to PSE&G's meter reading schedule, that can have a single billing month encompass up to four calendar-months, follows.

Section III will describe the implementation of the estimation of the calendar-month sales and revenue process at PSE&G.

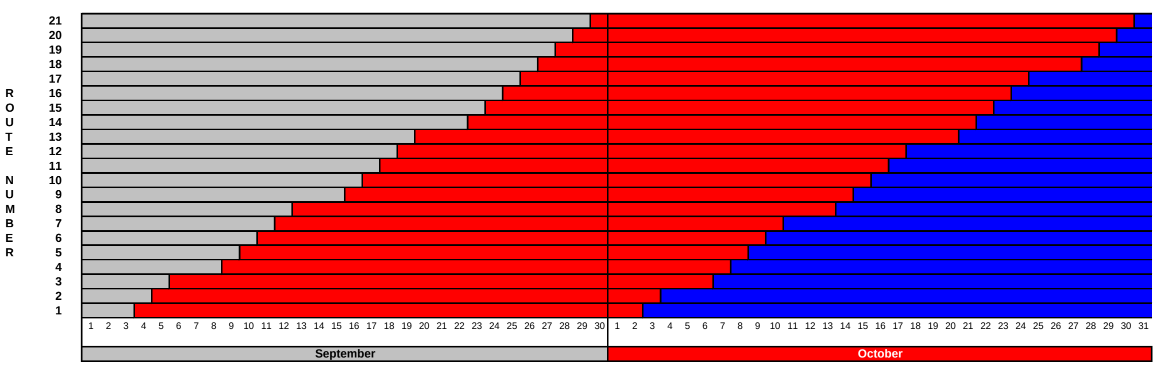
The Unbilled and Calendar-Month Estimation

A Simple Example

Utilities generally read all of their meters every month on 21 workdays. Figure 1, below shows a hypothetical October billing-month (in red) as determined by the September and October meter reading schedules. In the chart, each row represents a Route Number or a group of meters that are always read on the same day (although the day when they are all read may vary from month to month). The bottom row is red on all the days after the September read date, September 3rd until the October read date, October 2nd. If it is assumed that the customers' meters are read at noon, the October bill to these customers will reflect 28.5 days of service in September and only 1.5 days in October[2]. The second row from the bottom represents Route 2 whose customers' meters were read on September 4th and October 3rd. The October bill to these customers will reflect 27.5 days of service in September and only 2.5 days in October. This continues until the top row, Route 21, that had meter reading days of September 29th and October 30th. The October bills to these customers represent only 1.5 days of September service and 29.5 days of October service.

Figure 1

Hypothetical October 2008 Billing-Month



From the red portion of the diagram, it can be seen that the October billing-month consists of September sales that are billed in October that, to facilitate discussion, will be referred to as $\boxed{\text{SEP B> OCT}}$ and October sales that are billed in October i.e., $\boxed{\text{OCT B> OCT}}$. The calendar-month sales are defined as the red and blue rectangle defined by the month of October and the 21 read-cycles. This consists of $\boxed{\text{OCT B> OCT}}$ sales and the October unbilled sales, $\boxed{\text{OCT B> NOV}}$, the October sales that will be billed in November.

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[2] Or, more realistically, if the meter reads for all the Route 1 customers are evenly distributed throughout an 8:00 AM to 4:00 PM workday, the reads, on average, would represent a half day's sales on the read day.

The relationship between billed, unbilled, and calendar-month sales can be derived from these identities from the steps below.

$$\text{October Calendar} = \boxed{\text{OCT B> OCT}} + \boxed{\text{OCT B> NOV}} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{OCT B> NOV}\end{array}} \qquad [1]$$

Adding and subtracting $\boxed{\text{SEP B> OCT}}$ to the r.h.s. of [1] yields:

$$\text{October Calendar} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{OCT B> NOV}\end{array}} + \boxed{\text{SEP B> OCT}} - \boxed{\text{SEP B> OCT}} \qquad [2]$$

Rearranging the r.h.s. of [2] yields:

$$\text{October Calendar} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{SEP B> OCT}\end{array}} + \boxed{\text{OCT B> NOV}} - \boxed{\text{SEP B> OCT}} \qquad [3]$$

Substituting [1] into the l.h.s. of [3] yields:

$$\boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{OCT B> NOV}\end{array}} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{SEP B> OCT}\end{array}} + \boxed{\text{OCT B> NOV}} - \boxed{\text{SEP B> OCT}} \qquad [4]$$

This is the familiar:

October Calendar = October Billed + October Unbilled – September Unbilled[3] [5]

This formula for the accrual of calendar-month sales and revenues is preferred to any direct estimation of calendar-month sales because any error in the unbilled estimate is
“reversed out” in the following month. The advantage of this is that, as the calendar time period extends, the potential error resulting from unbilled estimates is reduced. This can be seen by summing up [5] over the 2008 calendar-year as:

$$\text{Calendar-Year 2008} = \sum_{i=\text{JAN08}}^{\text{DEC08}} \text{Billed}_i + \sum_{i=\text{JAN08}}^{\text{DEC08}} \text{Unbilled}_i - \sum_{i=\text{DEC07}}^{\text{NOV08}} \text{Unbilled}_i \qquad [6]$$

[3] The difference between the current month’s unbilled and the previous month’s is often referred to as
the “net unbilled”.

Where:

$Billed_i$ = Billing-month sales in month i,
$Unbilled_i$ = Unbilled sales in month i.

That simplifies to:

$$\text{Calendar-Year 2008} = \sum_{i=JAN08}^{DEC08} Billed_i + Unbilled_{DEC08} - Unbilled_{DEC07} \qquad [7]$$

The key result from [7] is that the annual calendar-year sales are the annual billed sales, a very large real number, and the difference between two monthly unbilled estimates. Since the error that can be expected in the difference between the two monthly unbilled estimates can be assumed to be quite small compared to the annual billed total, the calendar-year estimate, as a result, can be expected to be very accurate.

The same general results described in this simple example apply to PSE&G's more complicated meter reading schedule that is described below.

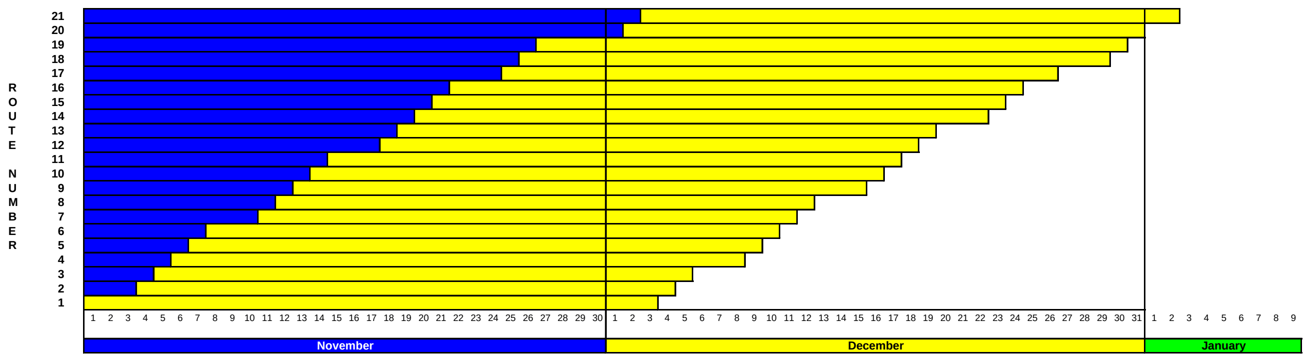
A More General Example

Unlike the hypothetical October billing-month, discussed above, that spanned two months, September and October, the PSE&G billing-month can encompass as many as four months. For example, the December 2008 PSE&G billing month, illustrated in Figure 2. has meter reading dates ranging from October 31st to January 2nd. As a result, it spans four months, October, November, December, and January[4].

[4] This is the original PSE&G December 2008 meter reading schedule. It has since been "compressed" to accommodate the implementation of iPower, the new billing and customer information system.

Figure 2

PSE&G December 2008 Billing-Month



Therefore, to develop a general algorithm applicable to PSE&G, the definition of billed, unbilled, and calendar sales must be expanded to include the potential of having sales from two additional calendar months reflected in a billing-month. December 2008 billing month, for example, is defined as:

$$\text{December Billed} = \boxed{\begin{array}{l}\text{OCT B> DEC}\\ \text{NOV B> DEC}\\ \text{DEC B> DEC}\\ \text{JAN B> DEC}\end{array}} \qquad [8]$$

Given the additional components of the billed, $\boxed{\text{OCT B> DEC}}$, i.e. the “under billed” sales, and $\boxed{\text{JAN B> DEC}}$, the “excess billed” sales, the addition of the current unbilled and subtraction of the previous month’s unbilled to the December billed, as defined in the simple example above, will overstate December calendar-month sales by the sum of under billed and excess billed sales. As a result, the December unbilled needs to be redefined as:

$$\text{December Unbilled} = \boxed{\begin{array}{l}\text{DEC B> JAN}\\ \text{DEC B> FEB}\end{array}} + \boxed{\text{NOV B> JAN}} - \boxed{\text{JAN B> DEC}} \qquad [9]$$

December Unbilled = December Unbilled
+ January Underbilled – December Excess Billed [10]

December calendar can then be defined as December billed plus the new

December unbilled less the equivalent November unbilled or:

$$\boxed{\begin{array}{l}\text{DEC B> OCT}\\ \text{DEC B> NOV}\\ \text{DEC B> DEC}\\ \text{DEC B> JAN}\end{array}} = \boxed{\begin{array}{l}\text{OCT B> DEC}\\ \text{NOV B> DEC}\\ \text{DEC B> DEC}\\ \text{JAN B> DEC}\end{array}}$$

$$+ \boxed{\begin{array}{l}\text{DEC B> JAN}\\ \text{DEC B> FEB}\end{array}} + \boxed{\text{NOV B> JAN}} - \boxed{\text{JAN B> DEC}}$$

$$- \boxed{\begin{array}{l}\text{NOV B> DEC}\\ \text{NOV B> JAN}\end{array}} - \boxed{\text{OCT B> DEC}} + \boxed{\text{DEC B> NOV}} \qquad [11]$$

or, in words:

$$\begin{array}{ll}\text{December Calendar} & = \text{December Billed}\\ & + \text{December Unbilled}\\ & - \text{November Unbilled}\end{array} \qquad [12]$$

This is the general formula that is used to calculate unbilled sales at PSE&G.

The PSE&G Gas Calendar-Month Estimation

The estimation of calendar-month gas sales at PSE&G is based on the notion that gas sales can be divided into two components: a weather sensitive component and a non-weather sensitive component. The weather sensitive component is affected by the winter weather as measured by heating degree days (HDD). The non-weather component is simply a function of the number of days in the sales period. As a result, sales during the unbilled periods can be estimated based on the HDD and number of days during the unbilled periods and the estimates of the weather-sensitive sales per HDD and non-weather sensitive sales per day.

The estimate of the weather-sensitive sales per HDD for each rate, the HDD coefficient, is the sum of the coefficients associated with its model's independent variables that have a HDD component divided by the number of days in the billing period. In the case of RSG that, unlike the other rates, is modeled on a use per customer basis, this result is multiplied by the number of customers.

The estimate of the non-weather sensitive sales per day for each rate, the base coefficient, is the value of the model equation with all of the coefficients associated with HDD set to zero and divided by the number of days in the billing period. As in the case of the HDD coefficient, the RSG result is multiplied by the number of customers.

Given the structure of the models, these coefficients will vary by month and by year. The current estimates for 2008 and 2009 are shown in Table 1 below.[5]

Table 1

Unbilled Weather and Base Coefficients, 2008-2009

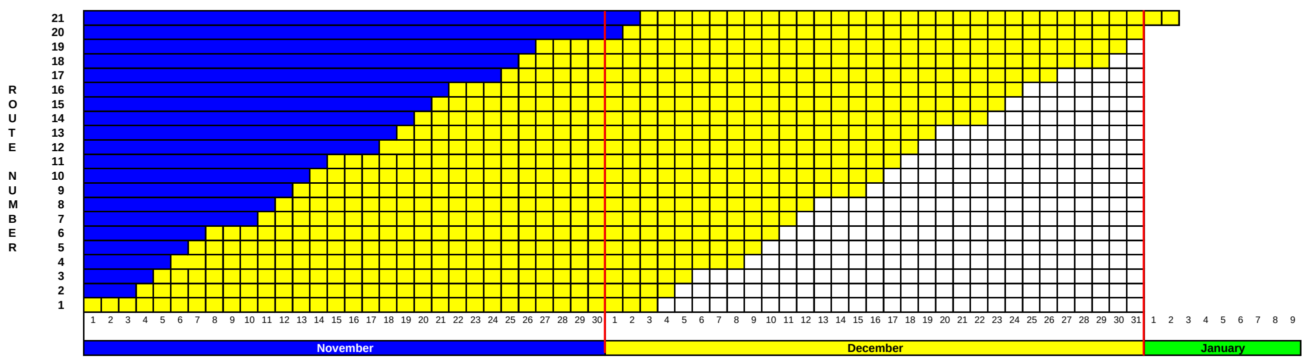
	RSG				GSG-Commercial				GSG-Industrial				LVG - Non Vehicle			
Billing	Heating		Non-heating		Heating		Non-heating		Heating		Non-heating		Commercial		Industrial	
Month	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD
Jan-08	1,477,624	246,082	218,393	4,689	56,941	45,607	168,133	3,942	(15,873)	3,333	2,978	501	1,047,971	79,608	145,023	8,767
Feb-08	1,554,914	253,674	234,372	4,811	69,746	45,607	175,674	3,942	(15,256)	3,333	3,786	501	1,172,070	79,608	167,056	8,767
Mar-08	1,343,904	249,936	236,373	4,737	25,553	45,607	158,654	3,942	(16,832)	3,333	2,893	501	1,053,237	79,608	138,433	8,767
Apr-08	1,337,980	248,305	190,526	4,692	13,895	45,607	150,129	3,942	(15,769)	3,333	5,681	501	1,076,058	79,608	159,387	8,767
May-08	1,267,108	251,443	164,912	4,741	146,976	45,607	117,463	3,942	332	3,333	4,166	501	838,647	79,608	137,277	8,767
Jun-08	1,086,639	250,233	135,407	4,714	126,187	45,607	95,849	3,942	2,561	3,333	3,704	501	708,324	79,608	129,981	8,767
Jul-08	984,641	248,954	116,905	4,704	135,270	45,607	94,660	3,942	3,907	3,333	2,680	501	610,707	79,608	119,171	8,767
Aug-08	912,999	249,456	104,709	4,666	103,926	45,607	80,601	3,942	2,045	3,333	2,578	501	613,535	79,608	119,770	8,767
Sep-08	940,487	252,748	111,693	4,746	108,515	45,607	84,252	3,942	2,953	3,333	2,730	501	581,470	79,608	129,852	8,767
Oct-08	809,244	249,439	113,383	4,671	115,541	45,607	90,002	3,942	3,184	3,333	1,932	501	728,815	79,608	116,580	8,767
Nov-08	1,076,293	250,792	138,927	4,687	(9,962)	45,607	107,114	3,942	(7,929)	3,333	5,262	501	769,823	79,608	112,495	8,767
Dec-08	1,191,333	252,604	187,367	4,690	(9,608)	45,607	130,211	3,942	(18,805)	3,333	2,214	501	902,036	79,608	120,543	8,767
Jan-09	1,481,212	248,163	214,955	4,643	56,601	45,745	153,926	3,711	(15,827)	3,259	2,952	490	1,041,705	79,850	144,156	8,190
Feb-09	1,548,542	252,236	228,920	4,692	69,856	45,745	171,980	3,711	(15,254)	3,259	3,796	490	1,173,921	79,850	167,320	8,190
Mar-09	1,393,454	253,517	239,084	4,687	26,121	45,745	168,175	3,711	(17,054)	3,259	2,980	490	1,076,642	79,850	141,509	8,190
Apr-09	1,331,091	250,149	185,138	4,617	13,721	45,745	148,255	3,711	(15,497)	3,259	5,622	490	1,062,628	79,850	157,398	8,190
May-09	1,266,433	253,309	160,992	4,665	145,815	45,745	116,535	3,711	352	3,259	4,136	490	832,022	79,850	136,193	8,190
Jun-09	1,094,707	252,091	133,240	4,638	126,187	45,745	95,849	3,711	2,565	3,259	3,704	490	708,324	79,850	129,981	8,190
Jul-09	987,359	250,802	114,502	4,629	134,644	45,745	94,222	3,711	3,889	3,259	2,668	490	607,880	79,850	118,620	8,190
Aug-09	925,740	251,308	103,701	4,591	104,600	45,745	81,124	3,711	2,058	3,259	2,595	490	617,512	79,850	120,546	8,190
Sep-09	953,382	254,625	110,592	4,670	109,193	45,745	84,778	3,711	2,971	3,259	2,747	490	585,098	79,850	130,662	8,190
Oct-09	808,699	251,291	110,672	4,596	114,612	45,745	89,279	3,711	3,169	3,259	1,918	490	722,957	79,850	115,643	8,190
Nov-09	1,077,388	252,654	135,835	4,612	(9,899)	45,745	106,433	3,711	(7,834)	3,259	5,235	490	764,927	79,850	111,779	8,190
Dec-09	1,203,734	254,479	184,915	4,615	(9,637)	45,745	130,597	3,711	(18,750)	3,259	2,238	490	904,708	79,850	120,900	8,190

[5] While the coefficient is called the "base" coefficient, it really does not measure base use per day. Rather it is the intercept term in a simple regression. As a result, it can be negative reflecting the intercept of a regression that is outside of the relevant range.

The billed, unbilled, excess billed, and underbilled days and heating degree days are derived from the meter reading schedule and daily weather data. The measure used is the Average Route Days (ARD). The ARD are defined as the number of days across all routes for a given period divided by 21, the total number of routes. This concept is illustrated in Figure 3, a slightly different version of the December 2008 billing-month, shown below.

Figure 3

PSE&G December 2008 Billing-Month



Each square represents an ARD.[6] The total yellow blocks in each row represent the number of days in that particular route during the December billing-month. The sum of all the yellow blocks, 677, divided by 21 represent the average number of days in the December billing-month, i.e., the average number of days across the 21 routes or 32.24.

The number of excess billed days, JAN B> DEC , is:

1.5 (January 1^{st} and half of January 2^{nd}) / 21 = 0.07 [13]

HDD for each period are a weighted sum of the daily HDD where the weight is the ARD associated with that day. For example, from the diagram it can be seen that on December 21^{st}, the sales to 8 routes, routes 14-21, will be in the

[6] Well, not exactly. Remember that it is assumed that the meters are read at noon. As a result the last yellow block to the right of each row counts as a half day. On the other hand, the last blue block on the right of each row also counts as a half day in the December billing-month so, the math works for the billing-month but, the half needs to be taken into account when discussing portions of the unbilled and billed periods. For a clearer discussion, however, the half days will be, for the most part, ignored.

December billing-month while sales to the first thirteen routes will be in the January billing-month. As a result , 8/21 or 38 percent of the HDD on December 20th will be assigned to the December billing month and 62 percent will be assigned to the January billing month.

HDD for underbilled and excess billed periods are assigned in a similar manner.

From Table 2 below that shows the normal monthly billed an unbilled HDD and days by type, it can be seen that underbilled days and HDD occur rarely while excess billed days are quite common.

Table 2

Billed and Unbilled Days and Weather 2008-2009

	Heating Degree Days				Days			
Billing Month	Billed	Unbilled	Excess Billed	Under Billed	Billed	Unbilled	Excess Billed	Under Billed
Jan-08	795.06	322.08	0.59	-	31.67	12.76	0.02	0.00
Feb-08	786.44	283.76	5.90	-	30.19	11.83	0.29	0.00
Mar-08	643.82	187.74	2.62	-	30.67	12.10	0.21	0.00
Apr-08	360.41	73.05	0.20	-	30.14	11.83	0.10	0.00
May-08	108.21	13.78	0.05	-	29.90	13.05	0.21	0.00
Jun-08	15.47	0.14	-	-	30.33	12.60	0.10	0.00
Jul-08	0.14	-	-	-	30.71	12.81	0.02	0.00
Aug-08	0.01	0.03	-	-	29.57	14.29	0.07	0.00
Sep-08	1.87	7.02	0.04	-	30.71	13.52	0.02	0.00
Oct-08	60.34	87.80	-	-	29.38	15.12	0.00	0.00
Nov-08	255.88	213.78	1.65	-	29.76	15.43	0.10	0.00
Dec-08	578.34	338.40	1.75	0.17	32.24	14.19	0.07	0.02
Jan-09	797.36	361.02	1.75	-	31.86	13.33	0.07	0.00
Feb-09	786.19	277.80	7.41	-	30.14	11.48	0.36	0.00
Mar-09	634.56	188.08	1.17	-	30.00	12.21	0.10	0.00
Apr-09	361.92	73.58	0.46	-	30.52	11.79	0.19	0.00
May-09	108.91	13.36	0.05	-	30.14	12.67	0.21	0.00
Jun-09	15.07	0.12	-	-	30.33	12.21	0.10	0.00
Jul-09	0.12	-	-	-	30.86	12.38	0.12	0.00
Aug-09	0.01	0.03	-	-	29.38	13.90	0.02	0.00
Sep-09	1.97	6.92	0.04	-	30.52	13.38	0.02	0.00
Oct-09	61.71	86.34	-	-	29.62	14.74	0.00	0.00
Nov-09	261.34	207.03	1.65	-	29.95	14.88	0.10	0.00
Dec-09	582.57	329.38	3.90	-	32.14	13.81	0.17	0.00

On a monthly basis, the necessary coefficient, weather, and day data are transmitted to PSE&G accounting services each month. They are used to calculate the actual current month unbilled sales, UnbilledTherms, using:

UnbilledTherms = UnbilledDays x BASECoef + UnbilledHDD x HDDCoef [14]

Where:

UnbilledDays = the number of route days in the unbilled period as defined by [9],

Unbilled HDD = the number of HDD in the unbilled period as defined by [9],

BASECoef = the Base coefficient,

HDDCoef = the HDD coefficient.

The results of this calculation, with the previous month's unbilled results, are used to calculate calendar-month sales.

Unbilled, and as a consequence, calendar-month revenue is calculated by pricing the unbilled therms at the projected tariff rates. Adding the net unbilled revenue to the billing-month revenues results in the estimate of calendar-month revenue.

B. Summary Tables

Delivered Gas Sales As Billed
2015-2026
(MDth)

Class	Rate	Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	RSG	Heating	143,469	125,945	138,594	139,827	140,686	140,458	141,740	143,256	147,699	149,326	151,498	153,436
		Non-Heating	9,598	8,549	8,864	8,830	8,705	8,654	8,613	8,542	8,432	8,274	8,427	8,375
	Total		153,067	134,494	147,458	148,658	149,392	149,112	150,354	151,799	156,131	157,601	159,924	161,811
Commercial	GSG	Heating	24,044	21,075	23,155	23,022	23,124	23,362	23,584	23,706	23,872	24,024	24,813	24,957
		Non-Heating	4,193	3,819	4,002	3,996	3,995	3,996	3,998	3,992	3,991	3,991	3,993	3,990
		Total	28,237	24,894	27,156	27,019	27,119	27,358	27,582	27,698	27,863	28,016	28,805	28,947
	LVG		65,580	58,437	62,260	62,261	62,420	62,626	62,925	63,064	63,327	63,450	63,732	63,932
	TSG	Firm	1,066	945	921	921	921	921	921	921	921	921	921	921
		Non-Firm	17,324	16,683	13,596	13,596	13,596	13,596	13,596	13,596	13,596	13,596	13,596	13,596
		Total	18,390	17,628	14,518	14,518	14,518	14,518	14,518	14,518	14,518	14,518	14,518	14,518
	CIG		3,724	3,242	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527
	CSG		15,922	16,728	-	-	-	-	-	-	-	-	-	-
	Total		131,852	120,930	107,461	107,324	107,584	108,028	108,551	108,807	109,235	109,510	110,582	110,923
Industrial	GSG	Heating	969	803	886	887	885	882	878	872	867	861	856	852
		Non-Heating	164	148	157	157	157	157	157	157	157	157	157	157
		Total	1,133	950	1,043	1,043	1,042	1,038	1,035	1,029	1,024	1,018	1,013	1,009
	LVG		7,731	6,788	7,110	7,112	7,111	7,094	7,079	7,054	7,035	7,004	6,988	6,968
	TSG	Firm	1,522	1,415	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
		Non-Firm	19,899	20,937	23,633	23,633	23,633	23,633	23,633	23,633	23,633	23,633	23,633	23,633
		Total	21,421	22,351	25,097	25,097	25,097	25,097	25,097	25,097	25,097	25,097	25,097	25,097
	CIG		1,119	688	589	589	589	589	589	589	589	589	589	589
	CSG		125,946	113,324	126,624	126,624	126,624	126,624	126,624	126,624	126,624	126,624	126,624	126,624
	Contract		36,053	25,237	-	-	-	-	-	-	-	-	-	-
	Total		193,403	169,339	160,464	160,466	160,464	160,443	160,425	160,393	160,369	160,332	160,311	160,288
Lighting	SLG		68	64	64	64	64	64	64	64	64	64	64	64
Total			478,323	424,763	415,384	416,448	417,440	417,583	419,330	420,999	425,735	427,443	430,818	433,022

			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	GSG		29,370	25,844	28,200	28,062	28,161	28,397	28,617	28,727	28,887	29,033	29,818	29,955
	LVG		73,311	65,225	69,370	69,373	69,532	69,719	70,004	70,118	70,362	70,454	70,720	70,900
	TSG		2,587	2,359	2,385	2,385	2,385	2,385	2,385	2,385	2,385	2,385	2,385	2,385
			37,223	37,620	37,230	37,230	37,230	37,230	37,230	37,230	37,230	37,230	37,230	37,230

Supplied Gas Sales As Billed
2015-2026
(MDth)

Class	Rate	Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	RSG	Heating	134,729	119,460	132,751	133,931	134,755	134,536	135,764	137,216	141,473	143,032	145,112	146,969
		Non-Heating	8,995	8,064	8,466	8,434	8,315	8,266	8,227	8,159	8,053	7,903	8,048	7,999
	Total		143,724	127,524	141,217	142,365	143,069	142,802	143,991	145,375	149,526	150,935	153,160	154,968
Commercial	GSG	Heating	18,565	16,082	17,688	17,587	17,666	17,849	18,021	18,114	18,243	18,361	18,969	19,081
		Non-Heating	3,035	2,757	2,885	2,882	2,880	2,882	2,883	2,879	2,878	2,878	2,879	2,877
		Total	21,600	18,839	20,574	20,469	20,547	20,731	20,904	20,993	21,121	21,239	21,848	21,958
	LVG		27,301	21,264	24,689	22,724	24,751	22,868	24,964	23,028	25,122	23,182	25,299	23,360
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	919	723	897	897	897	897	897	897	897	897	897	897
		Total	919	723	897	897	897	897	897	897	897	897	897	897
	CIG		3,724	3,242	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527
	CSG		-	-	-	-	-	-	-	-	-	-	-	-
	Total		53,544	44,068	49,686	47,617	49,721	48,023	50,292	48,445	50,668	48,845	51,571	49,742
Industrial	GSG	Heating	778	639	703	703	702	699	696	691	687	682	678	675
		Non-Heating	123	108	117	117	117	117	117	117	117	117	117	117
		Total	902	747	820	820	819	816	814	808	804	799	796	792
	LVG		2,013	1,637	1,902	1,903	1,903	1,899	1,894	1,884	1,879	1,870	1,864	1,858
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	55	151	222	222	222	222	222	222	222	222	222	222
		Total	55	151	222	222	222	222	222	222	222	222	222	222
	CIG		1,119	688	589	589	589	589	589	589	589	589	589	589
	CSG		-	-	-	-	-	-	-	-	-	-	-	-
	Contract		2,590	2,114	-	-	-	-	-	-	-	-	-	-
	Total		6,679	5,337	3,533	3,534	3,533	3,526	3,518	3,503	3,494	3,480	3,471	3,462
Lighting	SLG		28	26	25	25	25	25	25	25	25	25	25	25
Total			203,947	176,930	194,437	193,516	196,324	194,350	197,802	197,323	203,688	203,260	208,202	208,172

Supplied Share of Delivered Gas Sales As Billed
2015-2026
(percent)

Class	Rate	Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	RSG	Heating	94%	95%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
		Non-Heating	94%	94%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
	Total		94%	95%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
Commercial	GSG	Heating	77%	76%	76%	76%	76%	76%	76%	76%	76%	76%	76%	76%
		Non-Heating	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%
		Total	76%	76%	76%	76%	76%	76%	76%	76%	76%	76%	76%	76%
	LVG		42%	36%	40%	36%	40%	37%	40%	37%	40%	37%	40%	37%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	5%	4%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
		Total	5%	4%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		41%	36%	46%	44%	46%	44%	46%	45%	46%	45%	47%	45%
Industrial	GSG	Heating	80%	80%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%
		Non-Heating	75%	73%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
		Total	80%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%
	LVG		26%	24%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
		Total	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Contract		7%	8%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Lighting	SLG		41%	41%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Total			43%	42%	47%	46%	47%	47%	47%	47%	48%	48%	48%	48%

Delivered Gas Sales Calendar-Year
2015-2026
(MDth)

Class	Rate	Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	RSG	Heating	140,336	130,626	137,515	139,837	140,652	141,067	141,458	143,278	147,689	150,168	151,356	153,249
		Non-Heating	9,413	8,788	8,755	8,817	8,682	8,676	8,590	8,530	8,408	8,290	8,423	8,356
	Total		149,749	139,414	146,270	148,655	149,335	149,743	150,048	151,809	156,097	158,458	159,779	161,604
Commercial	GSG	Heating	23,418	21,873	23,008	22,979	23,082	23,442	23,523	23,681	23,822	24,114	24,763	24,906
		Non-Heating	4,114	3,914	3,990	3,991	3,987	4,006	3,989	3,989	3,984	4,002	3,986	3,983
		Total	27,532	25,786	26,999	26,970	27,069	27,448	27,512	27,670	27,806	28,116	28,748	28,888
	LVG		63,808	60,401	61,799	62,167	62,321	62,816	62,780	63,009	63,210	63,660	63,615	63,811
	TSG	Firm	1,038	958	889	921	921	921	921	921	921	921	921	921
		Non-Firm	14,957	15,183	13,415	13,596	13,596	13,596	13,596	13,596	13,596	13,596	13,596	13,596
		Total	15,995	16,141	14,305	14,518	14,518	14,518	14,518	14,518	14,518	14,518	14,518	14,518
	CIG		3,651	3,166	3,505	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527
	CSG		11,685	13,634	-	-	-	-	-	-	-	-	-	-
	Total		122,671	119,128	106,607	107,182	107,434	108,309	108,337	108,723	109,060	109,820	110,409	110,745
Industrial	GSG	Heating	952	823	882	885	883	884	875	871	865	864	854	850
		Non-Heating	144	152	157	157	156	157	156	156	156	157	156	156
		Total	1,096	975	1,039	1,042	1,040	1,042	1,032	1,027	1,021	1,021	1,010	1,006
	LVG		7,526	6,995	7,090	7,103	7,099	7,111	7,061	7,046	7,020	7,021	6,973	6,954
	TSG	Firm	1,505	1,393	1,504	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
		Non-Firm	19,620	21,872	24,180	23,633	23,633	23,633	23,633	23,633	23,633	23,633	23,633	23,633
		Total	21,125	23,265	25,684	25,097	25,097	25,097	25,097	25,097	25,097	25,097	25,097	25,097
	CIG		1,164	687	571	589	589	589	589	589	589	589	589	589
	CSG		118,452	108,304	126,851	126,624	126,624	126,624	126,624	126,624	126,624	126,624	126,624	126,624
	Contract		35,878	25,913	-	-	-	-	-	-	-	-	-	-
	Total		185,242	166,140	161,235	160,455	160,449	160,463	160,403	160,383	160,352	160,352	160,294	160,270
Lighting	SLG		68	64	64	64	64	64	64	64	64	64	64	64
Total			457,662	424,682	414,112	416,291	417,218	418,515	418,787	420,915	425,509	428,630	430,481	432,619

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
GSG	28,628	26,762	28,037	28,012	28,109	28,490	28,544	28,697	28,827	29,137	29,759	29,894
LVG	71,334	67,396	68,889	69,270	69,419	69,927	69,841	70,054	70,230	70,681	70,589	70,765
TSG	2,543	2,351	2,393	2,385	2,385	2,385	2,385	2,385	2,385	2,385	2,385	2,385
	34,578	37,055	37,595	37,230	37,230	37,230	37,230	37,230	37,230	37,230	37,230	37,230
CIG	4,815	3,853	4,076	4,116	4,116	4,116	4,116	4,116	4,116	4,116	4,116	4,116
CSG	130,137	121,938	126,851	126,624	126,624	126,624	126,624	126,624	126,624	126,624	126,624	126,624
Contract	35,878	25,913	-	-	-	-	-	-	-	-	-	-

Supplied Gas Sales Calendar-Year
2015-2026
(MDth)

Class	Rate	Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	RSG	Heating	132,140	124,069	131,400	133,941	134,722	135,120	135,493	137,237	141,463	143,839	144,976	146,789
		Non-Heating	8,837	8,297	8,340	8,421	8,292	8,286	8,204	8,147	8,030	7,918	8,045	7,980
	Total		140,977	132,367	139,740	142,362	143,015	143,407	143,698	145,385	149,493	151,756	153,021	154,770
Commercial	GSG	Heating	18,146	16,764	17,416	17,554	17,634	17,911	17,974	18,095	18,205	18,430	18,931	19,042
		Non-Heating	2,995	2,833	2,852	2,878	2,875	2,889	2,876	2,876	2,873	2,886	2,874	2,872
		Total	21,142	19,597	20,267	20,432	20,509	20,799	20,850	20,971	21,078	21,316	21,805	21,914
	LVG		26,549	21,882	24,419	22,687	24,712	22,942	24,909	23,007	25,077	23,263	25,254	23,314
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	910	789	867	897	897	897	897	897	897	897	897	897
		Total	910	789	867	897	897	897	897	897	897	897	897	897
	CIG		3,651	3,166	3,505	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527
	CSG		-	-	-	-	-	-	-	-	-	-	-	-
	Total		52,251	45,434	49,058	47,543	49,645	48,165	50,183	48,402	50,579	49,002	51,483	49,652
Industrial	GSG	Heating	768	656	695	701	700	701	694	690	685	684	677	673
		Non-Heating	108	112	116	117	117	118	117	117	117	118	117	117
		Total	875	768	811	818	817	818	811	807	802	802	794	790
	LVG		1,928	1,677	1,925	1,900	1,899	1,904	1,888	1,881	1,874	1,876	1,860	1,854
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	55	196	201	222	222	222	222	222	222	222	222	222
		Total	55	196	201	222	222	222	222	222	222	222	222	222
	CIG		1,164	687	571	589	589	589	589	589	589	589	589	589
	CSG		-	-	-	-	-	-	-	-	-	-	-	-
	Contract		2,712	2,585	-	-	-	-	-	-	-	-	-	-
	Total		6,735	5,913	3,508	3,530	3,527	3,533	3,510	3,499	3,487	3,488	3,464	3,455
Lighting	SLG		28	26	25	25	25	25	25	25	25	25	25	25
Total			199,964	183,714	192,305	193,435	196,187	195,105	197,391	197,286	203,559	204,247	207,968	207,876

Supplied Share of Delivered Gas Sales Calendar Year 2015-2026 (percent)

Class	Rate	Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	RSG	Heating	94%	95%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
		Non-Heating	94%	94%	95%	96%	96%	96%	96%	96%	96%	96%	96%	96%
	Total		94%	95%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
Commercial	GSG	Heating	77%	77%	76%	76%	76%	76%	76%	76%	76%	76%	76%	76%
		Non-Heating	73%	72%	71%	72%	72%	72%	72%	72%	72%	72%	72%	72%
		Total	77%	76%	75%	76%	76%	76%	76%	76%	76%	76%	76%	76%
	LVG		42%	36%	40%	36%	40%	37%	40%	37%	40%	37%	40%	37%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	6%	5%	6%	7%	7%	7%	7%	7%	7%	7%	7%	7%
		Total	6%	5%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		43%	38%	46%	44%	46%	44%	46%	45%	46%	45%	47%	45%
Industrial	GSG	Heating	81%	80%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%
		Non-Heating	75%	74%	74%	75%	75%	75%	75%	75%	75%	75%	75%	75%
		Total	80%	79%	78%	79%	79%	79%	79%	79%	79%	79%	79%	79%
	LVG		26%	24%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
		Total	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Contract		8%	10%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		4%	4%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Lighting	SLG		41%	41%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Total			44%	43%	46%	46%	47%	47%	47%	47%	48%	48%	48%	48%

17. FERC Pipeline Activities

Item 17

FERC Pipeline Activities

Pipeline	Docket No.	Description
Texas Eastern	RP88-67, RP17-964, RP17-967	Pipeline anticipated that its multi-year environmental remediation of PCB costs would be ongoing beyond the original termination date of an existing settlement, so on March 15, 2017, it triggered an extension of its long-standing settlement to enable it to continue to collect dollars, but still subject to its original overall cost cap. Pursuant to an unopposed August 4, 2017 settlement that resolved all issues, parties agreed to extend the existing long-term agreement through November 30, 2027. Among other matters, the agreement reduced the original overall system cap of $622 million to $360 million, and provided for potential further term extensions. The Commission approved the settlement by order dated October 10, 2017.
Texas Eastern	RP17-519	True-up of incurred but as yet uncollected PCB costs attributable to the original time-frame of the RP88-67 settlement. Parties engaged in extensive settlement negotiations to agree upon a mechanism to share the $9 million in total costs across the system. An unopposed settlement resolving the limited matters subject to this case was filed at the Commission on March 3, 2017, and was approved by order dated September 20, 2017.

Transco	RP18-314	On January 2, 2018, Transco filed to modify its no-notice and priority rights to address recent increases in within-the-month imbalances. Because certain customers are using no-notice services in ways that are inconsistent with the way the pipeline was designed, other customers, such as the Company, are experiencing more frequent flow restrictions, thus reducing their operational flexibility. By order dated March 1, 2018, the Commission set these matters for technical conference, at which only a few customers expressed concerns. In order to limit the frequency and duration of operational flow orders that it is experiencing, the Company plans to file comments in support of the Transco filing.
Columbia	RP18-426	On February 5, 2018, Columbia filed to reduce its already-existing firm base rates, as well as its modernization-related rates, consistent with recent reductions in the federal income tax rates. The pipeline sought to make the rate reductions have immediate and retroactive effect. The Commission approved the rate reductions in its February 23, 2018 order, with the changes effective January 1, 2018.
FERC	RM18-11, RM18-12, and PL17-1	On March 15, 2018, the Commission initiated proceedings in response to the Tax Cuts and Jobs Act, as well as the decision issued by the court in United v. Federal Energy Regulatory Commission. By these actions, the Commission is (a)

		proposing a process that will allow it to determine which jurisdictional pipelines may be collecting unjust and unreasonable rates in light of the recent reduction in federal tax rates, (b) addressing changes related to accumulated deferred income taxes and bonus depreciation, and (c) acting to no longer permit a master limited partnership to recover an income tax allowance in its cost of service. Principally through its participation as a member of the American Gas Association, the Company is collaborating with other local distribution customers to reduce its pipeline rates as appropriate.
Transco	CP18-18	On November 15, 2017, Transco applied for approval of the Gateway Expansion Project, which is designed to provide an incremental firm daily quantity of 54,000 dekatherms/day to the Company at its Ridgefield and Paterson stations. Acting to meet increasing market demands from its firm customers, the Company has worked with the pipeline as an anchor shipper for the project, which has an as-filed in-service date of November 2020.
Transco	CP18-101	On March 1, 2018, Transco applied for Commission authorization of its Station 240 LNG modernization project. In order to continue to fully meet its tariff obligations to its customers, including the Company, Transco seeks Commission authorization to improve the facility’s efficiency, reliability, and safety. Because it relies upon the firm service received from Station 240 as an essential

		part of its peak day portfolio of contracts, the Company has been working with the pipeline to ensure that the facility is appropriately modernized.
Transco	CP17-490	On August 31, 2017, Transco filed to provide 190,000 dekatherms per day of firm service to certain customers as a part of its Rivervale South to Market Project. While not a customer of this project, the Company has actively engaged with the pipeline to ensure that its current firm services are not compromised in any way. In order to protect the Company's existing rights, the pipeline and the expansion shippers have agreed to abide by certain pressure requirements that will not apply to the Company. In response to Transco's Commission application, the Company filed comments confirming its understanding that the application will do nothing to degrade any aspect of its current firm services. The docket is pending further action.
Texas Eastern	CP18-26	On December 7, 2017, Texas Eastern applied for approval of the Lambertville East Expansion Project, which is designed to provide an incremental firm daily quantity of 30,000 dekatherms/day to the Company at its Hillsborough and Jamesburg stations. Acting to meet increasing market demands from its firm customers, the Company has worked with the pipeline as an anchor shipper for the project, which has an as-filed in-service date of November 2019.
Penn East	CP15-558	Expansion project will provide the infrastructure needed to remove capacity

		constraints, thus permitting volumes of low-cost, reliable Marcellus gas to flow to New Jersey and Pennsylvania. The Company is a foundation shipper, and has contracted for 125,000 dth/day of firm capacity. Application to FERC was made on September 24, 2015, and the Company filed comments in support. The Final Environmental Impact Statement was issued on April 7, 2017, finding that if the project is constructed according to its recommendations, most adverse impacts would be reduced to less than significant levels. The application received its Commission certificate on January 19, 2018.

18. Gas Supply Plan

Gas Procurement Objectives

Current & Forecasted Gas Service Requirements

Projected Sources of Capacity

Affiliate Relationship / Asset Management

Hedging Plan & Strategy

Capacity Releases / Off-System Sales

Item 18

Gas Supply Plan

1. Gas Procurement Objectives

As discussed in the body of the testimony of David F. Caffery herein, natural gas prices have decreased from the levels experienced at this time last year. From a historical perspective, natural gas continues to remain reasonably priced with, at the time of this BGSS Filing, the NYMEX prompt month trading at approximately $2.95 per Dekatherm. Prices have traded in a relatively tight range between $2.55 and $2.95 per Dekatherm since the middle of January, 2018. The forward NYMEX strip used by the Company shows that prices are expected to rise modestly from current levels through the first quarter of 2019, followed by a reduction for the balance of the BGSS period. Overall, the NYMEX strip through September, 2019 used for this year's BGSS Filing is approximately 15% below last year's (see the NYMEX forward strip included as Item 8). One of the primary drivers of this moderation in prices is the record natural gas production witnessed over the past 6 months. In anticipation of additional pipeline takeaway capacity coming online, primarily from the Marcellus/Utica region, producers have increased production levels significantly. In fact, an all-time production record of over 79 Bcf/d was achieved just recently. This represents an increase of over 7 Bcf/d (about 10%) above the year ago levels and accounts for much of the reason why prices have remained moderate despite national storage levels being below the 5 year average by greater than 25%. As a result of these market dynamics, the Company expects adequate supply at reasonable price levels to continue to exist throughout the upcoming BGSS period.

2. Current and Forecasted Gas Service Requirements

The Company's forecasted natural gas supply requirements are included herein as Item 16. Item 16 consists of two parts. First, Schedule F illustrates the Company's Peak Day Gas Requirements and Supply over the next five winter periods. This schedule illustrates both the forecasted peak day supply by winter period as well as the pipeline transportation, storage and peaking supplies that the Company will rely upon to meet those forecasted requirements. The second part of Item 16 is the

Company's updated Natural Gas Sales Forecast for 2018. This document provides the Company's natural gas sales forecast, as well as the current forecast methodology, the econometric sales models and the forecast assumptions.

3. Projected Sources of Capacity

The Company periodically reviews its pipeline transportation, storage and peaking capacity supplies to ensure that the optimal mix of capacity assets are maintained to meet its forecasted peak day and seasonal requirements at the lowest possible cost. Several changes in the Company's pipeline capacity portfolio have been made which are reflected in the instant BGSS Filing.

First, the Company has approximately 88,000 Dth/d of upstream firm transportation capacity on Texas Eastern. The Company has been able to optimize its capacity portfolio to obtain additional Marcellus gas supplies at a lower cost, thereby eliminating the need to continue to hold this piece of Texas Eastern capacity. The Company is able to turn back this transportation contract without sacrificing any peak day capacity that it maintains to meet its customers' needs. As a result, the Company terminated this contract effective October 31, 2017. This has resulted in an annual savings of $3.5 million, which is reflected in this BGSS filing. In addition, the Arlington/Steuben contract, with a withdrawal capacity of approximately 42,000 Dth/d and an associated top gas capacity of 4.4 Bcf was terminated by the Company effective March 31, 2018. This contract termination resulted in an annual savings to the Company's customers of an additional $4.4 million, and again was enabled by the Company's ability to replace this supply with lower cost purchases directly from the Marcellus region.

Further, as mentioned in last year's BGSS filing, the Company has taken cER&Tain steps to ensure that it continues to meet its projected peak day capacity requirements to serve its firm customers. As illustrated on Item 16, based on the Company's latest forecast, it is projected that the Company will experience a shortfall in peak day supply commencing in 2018/2019 and increasing throughout the five year forecast period. To meet the increased peak day capacity requirements the Company has entered into a precedent agreement with Texas Eastern to provide 30,000 Dth/d of incremental firm transportation capacity. A portion of this capacity, 16,329 Dth/d, consists of existing capacity that the Company was able to obtain last year and is reflected in the supply numbers included on Item 16. The balance of the capacity, 13,671 Dth/d, is projected to be available on November 1, 2019 to help meet the anticipated shortfall in peak day supply in the 2019/2020 winter.

In addition to this Texas Eastern capacity, the Company is planning to enter into a precedent agreement with Algonquin to add an additional 15,000 Dth/d of incremental firm transportation capacity to help meet its increased peak day requirements. This capacity is also expected to be in-service for November 1, 2019 and will help meet the anticipated shortfall in peak day supply for the 2019/2020 winter.

The Company has also entered a precedent agreement with Transco to obtain incremental firm transportation capacity to further help meet its projected peak day shortfall. The precedent agreement with Transco provides for 54,000 Dth/d of incremental firm capacity. This capacity is anticipated to be in-service on November 1, 2020 and will help meet the projected shortfall in peak day supply for the 2020/2021 winter.

In addition, The Company's Dominion FT agreement 200316 was formerly a storage injection service for 31,936 dth/day. The old contract number has been retained, but the old service itself has been replaced with an FT agreement with an entitlement of 41,813 dth/day that can be used more flexibly, and no longer limited to just storage-related transactions. This change was effective April 1, 2018. Dominion FT agreement 200317, with a capacity of 41,813 dth/day, was formerly a storage withdrawal service, and was a companion for old contract 200316. In light of the above conversion of contract 200316, contract 200317 has been terminated. This change was also effective April 1, 2018.

Finally, the Company is a shipper in the PennEast project which will provide increased capacity from the Marcellus shale region as well as provide a new independent source of pipeline supply and thereby increase the reliability of the Company's portfolio of firm pipeline transportation capacity. PennEast received its FERC CER&Tificate on January 19, 2018 and is currently seeking the required state and local permits to provide for construction to commence. Given this timeline, PennEast is targeting a late 2019 in-service date. As such, costs associated with the PennEast capacity are not included in the instant BGSS Filing.

As agreed to in the Stipulation between the Parties in last year's BGSS Filing, in addition to the description of the contract changes above, the following table represents a listing of all contracts that have been extended pursuant to their evergreen provisions during the last BGSS Filing period:

			Top	Daily
Counterparty	Rate	Contract	Gas	Contract
	Schedule	Number	Quantity	Quantity
Texas Eastern	FT-1	910553		25,018
Texas Eastern	FTS	330840		12,315
Texas Eastern	FTS - 5	330915		45,084
Texas Eastern	FTS - 5	330181		10,508
Texas Eastern	FTS - 7	331007		97,915
Texas Eastern	FTS - 8	331017		60,069
Texas Eastern	SS - 1	400123	3,737,160	62,286
Texas Eastern	SS - 1	400241	1,453,340	20,762
Texas Eastern	FT - 1	800604		40,526
Texas Eastern	CDS	800600		120,000
Texas Eastern	FT - 1	800601		26,115
Texas Eastern	FT - 1	800605		110,000
Texas Eastern	FT - 1	800602		15,000
Texas Eastern	FT - 1	800606		30,000
Texas Eastern	FT - 1	800603		40,000
Texas Eastern	FT - 1	910611		50,000
Transco	FT	1006312		72,450
Transco	FT	1044211		50,000
Transco	FT	9009846		73,500
Transco	FT	9146335		9,400
Transco	FT	9146336		9,850
Transco	FT	1002228		6,440
Transco	FT	1003688		425,930
Transco	FT	1003835		198,950
Transco	FT	1005002		13,248
Transco	FT	1033145		48,240
Transco	FT	1041156		50,000
Transco	LNG	1000824	1,333,817	273,331
Transco	LNG	9127690	15,525	2,070
Transco	S - 2	1000823	6,158,589	68,514
Transco	ESS	1008564	1,186,535	141,544
Transco	FT	9066768		43,300
Dominion	GSSTE	600043	14,249,916	162,995
Dominion	FTNT	200482		50,000
Dominion	FT	200391		22,019
Gulf South	FSS	661	1,000,000	100,000

4. Affiliate Relationships/Asset Management

The Company obtains its full natural gas requirements pursuant to the Requirements Contract entered into between the Company and PSEG Energy Resources and Trade (PSEG ER&T) effective May, 2002. Under this agreement, PSEG ER&T manages its portfolio of transportation, storage and peaking supply assets to meet the Company's natural gas requirements on an hourly, daily, weekly, monthly and annual basis. The Company meets with representatives of PSEG ER&T as needed to provide oversight of the procurement of supplies pursuant to the Requirements Contract. PSEG ER&T provides updates to the Company regarding changes to pipeline capacity under contract, hedging activities, supply and pricing trends, as well as market developments. In addition, the Company and PSEG ER&T work together to prepare the information provided in the annual BGSS Filing. Item 13 in this BGSS Filing includes a summary of the principal terms of the Requirements Contract.

5. Hedging Plan and Strategy

The Company has included as Item 11 in the instant BGSS Filing its PSE&G Quarterly Gas Hedging Reports, which have been filed with the NJBPU over the past year. As discussed in the testimony of David F. Caffery herein, the Company to date has hedged approximately 99% of its planned volume for the 2018 summer period, approximately 69% of its planned volume for the 2018-2019 winter period and approximately 38% of its planned volume for the 2019 summer period. Hedging for the winter 2019-2020 period has just begun.

In addition to its transportation and peaking assets, PSEG ER&T maintains approximately 70 Bcf of storage assets under contract with various pipeline suppliers. These storage assets are used to supplement flowing gas supplies when customer demand on the Company's distribution system increases during the winter period. The Company typically injects gas into its storages during the April through October timeframe, targeting a level of approximately 97% full by October 31st. Item 12 included herein provides the list of storage services under contract as well as the monthly ending storage inventory by contract for the past winter period. This illustrates the manner in which each storage service was utilized over the 2017-2018 winter.

6. Capacity Releases/Off-System Sales

The attached schedule provides a summary of the capacity release and off-system sales by the Company for the prior six calendar years and for the first four months of 2018. For the upcoming BGSS period that is covered by this filing, the Company has a total of approximately $ 39 million in credits attributed to capacity release and off-system sales.

For the prior period, the Company has continued to experience decreased margins in off-system sales and capacity release transactions, however, the extremely cold weather periods in late December, 2017 and January, 2018 significantly added to off-system sales results. As can be seen on the attached schedule, off-system sales margins for the 4 months ending April total $43 million, approximately 70% of last year's 12-month total. This pace of off-system sales is not anticipated to continue, however, as margins decrease back to normal levels and volumes decrease significantly during the summer and fall periods.

In addition, a number of significant pipeline expansions from the Marcellus and Utica supply regions have been placed into service over the past year, which have provided additional outlets for these shale gas supplies. The increased ability of these pipelines to move additional volumes to market has resulted in a decrease in the basis differentials between the Marcellus and Utica supply region and the Transco Z6 market, where the Company makes the majority of its off-system sales. The record high production levels and the projected additional pipeline capacity to be placed in-service over the next 6 to 12 months will continue to put significant downward pressure on capacity release and off-system sales margins throughout the upcoming BGSS period.

Item 18

Off System Sales -- Revenues, Costs and Margins

2012 - 2018

Year	BGSS-RSG OSS Revenue (1)	BGSS-RSG OSS Cost (2)	BGSS-RSG OSS Margins (3)
2012	$155,052,637	$102,869,794	$52,182,843
2013	$240,938,997	$120,566,928	$120,372,069
2014	$327,717,529	$143,452,710	$184,264,819
2015	$197,662,767	$61,941,827	$135,720,940
2016	$145,423,895	$86,729,138	$58,694,758
2017	$156,240,095	$96,425,765	$59,814,330
2018*	$88,404,223	$44,969,431	$43,434,793

*Note: Through April 2018

Attachment B

Redlined Tariff Sheets

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 54**
Superseding
B.P.U.N.J. No. 15 GAS **XXX Revised Sheet No. 54**

BGSS-RSG
BASIC GAS SUPPLY SERVICE-RSG
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE RSG
(Per Therm)

Estimated Non-Gulf Coast Cost of Gas	$ ~~0.040550~~ 0.056548
Capital Adjustment Charge (See Tariff Sheet Nos. 48 to 49)	0.000000
Adjusted Non-Gulf Coast Cost of Gas	~~0.040550~~ 0.056548
Estimated Gulf Coast Cost of Gas	~~0.290370~~ 0.250273
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery..	~~0.008310~~ 0.014480
Adjusted Cost of Gas	~~0.339230~~ 0.321301

Commodity Charge after application of losses: (Loss Factor = 2.0%)................. $ ~~0.346015~~ 0.327858

Commodity Charge including New Jersey Sales and Use Tax (SUT)................. $ ~~0.368938~~ 0.349579

The above Commodity Charge will be established on a level annualized basis immediately prior to the winter season of each year for the succeeding twelve-month period. The estimated average Non-Gulf and Gulf Coast Cost of Gas will be adjusted for any under- or over-recovery together with applicable interest thereon which may have occurred during the operation of the Company's previously approved Commodity Charge filing. Further, the Company will be permitted a limited self-implementing increase to the Commodity Charge on December 1 and February 1 of each year. These limited self-implementing increases, if applied, are to be in accordance with a Board of Public Utilities approved methodology. Commodity Charge decreases would be permitted at any time if applicable.

The difference between actual costs and Public Service's recovery of these costs shall be determined monthly. If actual costs exceed the recovery of these costs, an underrecovery or a negative balance will result. If the recovery of these costs exceeds actual costs, an overrecovery or a positive balance will result. Interest shall be applied monthly to the average monthly cumulative deferred balance, positive or negative, from the beginning to the end of the annual period. Monthly interest on negative deferred balances (underrecoveries) shall be netted against monthly interest on positive deferred balances (overrecoveries) for the annual period. A cumulative net positive interest balance at the end of the annual period is owed to customers and shall be returned to customers in the next annual period. A cumulative net negative interest balance shall be zeroed out at the end of the annual period. The sum of the calculated monthly interests shall be added to the overrecovery balance or subtracted from the underrecovery balance at the end of the annual period. The positive interest balance shall be rolled into the beginning under- or over-recovery balance of the subsequent annual period.

Pursuant to the Board's January 6, 2003 Order approving the BGSS price structure under Docket No. GX01050304 and the BGSS Pricing Proposal appended as Attachment A to and approved in that Order, Public Service Electric and Gas Company may issue a bill credit for its BGSS-RSG customers as detailed below.

Effective	BGSS-RSG Credit (per therm)	BGSS-RSG Credit including SUT (per therm)
April 1, 2018 through April 30, 2018	($0.140680)	($0.150000)
May 1, 2018	$0.000000	$0.000000

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 65**
Superseding
B.P.U.N.J. No. 15 GAS **XXX Revised Sheet No. 65**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for residential purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$5.46 in each month [$5.82 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge Including SUT	
$0.300343	$0.320241	per therm

Balancing Charge:

Charge	Charge Including SUT	
$~~0.084457~~ 0.096436	$~~0.090052~~ 0.102825	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs per the Board Order in Docket No. EO08030164. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Weather Normalization Charge:

This charge is designed to adjust base rate recoveries to offset the effects of abnormal weather on sales. The weather normalization charge applied in each winter period shall be based on the differences between actual and normal weather during the preceding winter period. Refer to the Weather Normalization Charge sheet of this Tariff for the current charge.

The Weather Normalization Charge will be combined with the Balancing Charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge and the Green Programs Recovery Charge will be combined with the Distribution Charge for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY | **XXX Revised Sheet No. 72**
Superseding
B.P.U.N.J. No. 15 GAS | **XXX Revised Sheet No. 72**

RATE SCHEDULE GSG
GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes where: 1) customer does not qualify for RSG and 2) customer's usage does not exceed 3,000 therms in any month. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$11.28 in each month [$12.03 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.247071	$0.263439	$0.247071	$0.263439	per therm

* Applicable to customers who have taken TPS supplied commodity service continuously since July 14, 1997.

Balancing Charge:

Charge	Charge Including SUT	
$~~0.084457~~ 0.096436	$~~0.090052~~ 0.102825	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs per the Board Order in Docket No. EO08030164. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 79**
Superseding
B.P.U.N.J. No. 15 GAS **XXX Revised Sheet No. 79**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$100.12 in each month [$106.75 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$3.7352	$3.9827	per Demand Therm

Distribution Charges:

	Per therm for the first 1,000 therms used in each month		Per therm in excess of 1,000 therms used in each month	
	Charges	Charges Including SUT	Charges	Charges Including SUT
Pre-July 14, 1997 *	$0.041215	$0.043945	$0.039335	$0.041941
Post July 14, 1997	$0.041215	$0.043945	$0.039335	$0.041941

*Applicable to customers who have taken TPS supplied commodity service continuously since July 14, 1997.

Balancing Charge:

Charge	Charge Including SUT	
$~~0.084457~~ 0.096436	$~~0.090052~~ 0.102825	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 112A**
Superseding
B.P.U.N.J. No. 15 GAS **XXX Revised Sheet No. 112A**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS
DELIVERY CHARGES:

Service Charge:
$536.08 in each month [$571.60 including New Jersey Sales and Use Tax (SUT)]

Distribution Charge:
Net Alternative Delivery Cost multiplied by the applicable Net Alternative Delivery Cost Factor divided by the Contracted Monthly Therms rounded to the nearest $0.000000 per therm.

Maintenance Charges:
Equals the Alternative Delivery Cost multiplied by the applicable Alternative Delivery Cost Factor divided by the Contract Monthly Therms rounded to the nearest $0.000000 per therm.

Plus any customer site-specific ongoing or continuing cost not directly related to the operation, maintenance or inspection of the customer's planned by-pass pipeline. This shall include, but not be limited to, periodic payments for rights-of-way, easements, pipeline cost differentials, permits or other such costs. These charges shall be expressed on a monthly levelized basis over the term of service.

Public Service will also take into consideration any operational or deliverability differences that would be reasonably expected between the pipeline and/or service over Public Service's distribution system in determining Delivery Charges. In no event shall the Delivery Charges be lower than an amount sufficient to generate a return on the capital investments made by Public Service and recovery of marginal and embedded costs, including depreciation, to provide service to the customer over the term of each CSG agreement.

Balancing Charge:
Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

Charge	Charge Including SUT	
$~~0.084457~~	$~~0.090052~~	per Balancing Use Therm
0.096436	0.102825	

Societal Benefits Charge:
This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by government. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge and applicable exemptions.

Green Programs Recovery Charge:
This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs per the Board Order in Docket No. EO08030164. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Green Programs Recovery Charge. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge and applicable exceptions.

Attachment B

Proposed Tariff Sheets

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 54**
Superseding
B.P.U.N.J. No. 15 GAS **XXX Revised Sheet No. 54**

BGSS-RSG

BASIC GAS SUPPLY SERVICE-RSG

COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE RSG

(Per Therm)

Estimated Non-Gulf Coast Cost of Gas	$ 0.056548
Capital Adjustment Charge (See Tariff Sheet Nos. 48 to 49)	0.000000
Adjusted Non-Gulf Coast Cost of Gas	0.056548
Estimated Gulf Coast Cost of Gas	0.250273
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery	0.014480
Adjusted Cost of Gas	0.321301
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$ 0.327858
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.349579

The above Commodity Charge will be established on a level annualized basis immediately prior to the winter season of each year for the succeeding twelve-month period. The estimated average Non-Gulf and Gulf Coast Cost of Gas will be adjusted for any under- or over-recovery together with applicable interest thereon which may have occurred during the operation of the Company's previously approved Commodity Charge filing. Further, the Company will be permitted a limited self-implementing increase to the Commodity Charge on December 1 and February 1 of each year. These limited self-implementing increases, if applied, are to be in accordance with a Board of Public Utilities approved methodology. Commodity Charge decreases would be permitted at any time if applicable.

The difference between actual costs and Public Service's recovery of these costs shall be determined monthly. If actual costs exceed the recovery of these costs, an underrecovery or a negative balance will result. If the recovery of these costs exceeds actual costs, an overrecovery or a positive balance will result. Interest shall be applied monthly to the average monthly cumulative deferred balance, positive or negative, from the beginning to the end of the annual period. Monthly interest on negative deferred balances (underrecoveries) shall be netted against monthly interest on positive deferred balances (overrecoveries) for the annual period. A cumulative net positive interest balance at the end of the annual period is owed to customers and shall be returned to customers in the next annual period. A cumulative net negative interest balance shall be zeroed out at the end of the annual period. The sum of the calculated monthly interests shall be added to the overrecovery balance or subtracted from the underrecovery balance at the end of the annual period. The positive interest balance shall be rolled into the beginning under- or over-recovery balance of the subsequent annual period.

Pursuant to the Board's January 6, 2003 Order approving the BGSS price structure under Docket No. GX01050304 and the BGSS Pricing Proposal appended as Attachment A to and approved in that Order, Public Service Electric and Gas Company may issue a bill credit for its BGSS-RSG customers as detailed below.

Effective	BGSS-RSG Credit (per therm)	BGSS-RSG Credit including SUT (per therm)
April 1, 2018 through April 30, 2018	($0.140680)	($0.150000)
May 1, 2018	$0.000000	$0.000000

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 65**
Superseding
B.P.U.N.J. No. 15 GAS **XXX Revised Sheet No. 65**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for residential purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$5.46 in each month [$5.82 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge Including SUT	
$0.300343	$0.320241	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.096436	$0.102825	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs per the Board Order in Docket No. EO08030164. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Weather Normalization Charge:

This charge is designed to adjust base rate recoveries to offset the effects of abnormal weather on sales. The weather normalization charge applied in each winter period shall be based on the differences between actual and normal weather during the preceding winter period. Refer to the Weather Normalization Charge sheet of this Tariff for the current charge.

The Weather Normalization Charge will be combined with the Balancing Charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge and the Green Programs Recovery Charge will be combined with the Distribution Charge for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 72**
Superseding
B.P.U.N.J. No. 15 GAS **XXX Revised Sheet No. 72**

RATE SCHEDULE GSG
GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes where: 1) customer does not qualify for RSG and 2) customer's usage does not exceed 3,000 therms in any month. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$11.28 in each month [$12.03 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 * Charge	Pre-July 14, 1997 * Charge Including SUT	All Others Charge	All Others Charge Including SUT	
$0.247071	$0.263439	$0.247071	$0.263439	per therm

* Applicable to customers who have taken TPS supplied commodity service continuously since July 14, 1997.

Balancing Charge:

Charge	Charge Including SUT	
$0.096436	$0.102825	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs per the Board Order in Docket No. EO08030164. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, Vice President Finance – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 79**
Superseding
B.P.U.N.J. No. 15 GAS **XXX Revised Sheet No. 79**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$100.12 in each month [$106.75 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$3.7352	$3.9827	per Demand Therm

Distribution Charges:

	Per therm for the first 1,000 therms used in each month		Per therm in excess of 1,000 therms used in each month	
	Charges	Charges Including SUT	Charges	Charges Including SUT
Pre-July 14, 1997 *	$0.041215	$0.043945	$0.039335	$0.041941
Post July 14, 1997	$0.041215	$0.043945	$0.039335	$0.041941

*Applicable to customers who have taken TPS supplied commodity service continuously since July 14, 1997.

Balancing Charge:

Charge	Charge Including SUT	
$0.096436	$0.102825	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 112A**
Superseding
B.P.U.N.J. No. 15 GAS **XXX Revised Sheet No. 112A**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS
DELIVERY CHARGES:

Service Charge:
$536.08 in each month [$571.60 including New Jersey Sales and Use Tax (SUT)]

Distribution Charge:
Net Alternative Delivery Cost multiplied by the applicable Net Alternative Delivery Cost Factor divided by the Contracted Monthly Therms rounded to the nearest $0.000000 per therm.

Maintenance Charges:
Equals the Alternative Delivery Cost multiplied by the applicable Alternative Delivery Cost Factor divided by the Contract Monthly Therms rounded to the nearest $0.000000 per therm.

Plus any customer site-specific ongoing or continuing cost not directly related to the operation, maintenance or inspection of the customer's planned by-pass pipeline. This shall include, but not be limited to, periodic payments for rights-of-way, easements, pipeline cost differentials, permits or other such costs. These charges shall be expressed on a monthly levelized basis over the term of service.

Public Service will also take into consideration any operational or deliverability differences that would be reasonably expected between the pipeline and/or service over Public Service's distribution system in determining Delivery Charges. In no event shall the Delivery Charges be lower than an amount sufficient to generate a return on the capital investments made by Public Service and recovery of marginal and embedded costs, including depreciation, to provide service to the customer over the term of each CSG agreement.

Balancing Charge:
Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

Charge	Charge Including SUT	
$0.096436	$0.102825	per Balancing Use Therm

Societal Benefits Charge:
This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by government. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge and applicable exemptions.

Green Programs Recovery Charge:
This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs per the Board Order in Docket No. EO08030164. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Green Programs Recovery Charge. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge and applicable exceptions.

<u>Attachment D</u>

Support for Balancing Charge

& Storage Inventory Carrying Charge

(Including Update for A&G Charge)

Balancing Charge - Annual Allocated Cost

Firm Capacity Allocation:	**Total** (Mdth/day)	**Capacity Used for Balancing** (Mdth/day)	**Percent Allocated to Balancing Use**
Base FT	789.5	0.0	0.0%
Storage	900.7	500.1	55.5%
Balancing FT	425.9	425.9	100.0%
Peaking	553.4	553.4	100.0%
	2,669.5	1,479.4	

	Total Cost	**Percent Allocated to Balancing Use**	**Allocated Cost**
Fixed Cost Allocation:			
Base FT	$135,591.1	0.0%	$0.0
Storage	$96,979.3	55.5%	$53,849.3
Balancing FT	$63,202.6	100.0%	$63,202.6
Peaking	$9,808.9	100.0%	$9,808.9
Variable Cost Allocation:			
Base FT	$0.0	0.0%	$0.0
Storage	$6,711.2	55.5%	$3,726.5
Balancing FT	$0.0	100.0%	$0.0
Peaking	$2,169.7	100.0%	$2,169.7

Total Annual Allocated Costs ($000)	**$ 132,756.9**
Balancing Use Billing Determinants - Nov - Mar (MDth)	151,758
Balancing Charge - Annual Allocated Cost ($/Dth)	$ 0.87480
Storage Inventory Carrying Charge ($/Dth) (page 2)	$ 0.04352
Revenue Requirement on Gas Production Plant Charge ($/Dth) (page 3)	$ 0.02675
Total Balancing Charge (excl. losses) ($/Dth)	$ 0.94507
Total Balancing Charge (incl. losses @ 2%) ($/Dth)	$ 0.96436
Total Balancing Charge (incl. SUT) ($/Dth)	**$ 1.02825**
Total Balancing Charge (incl. SUT) ($/Therm)	**$ 0.102825**

Storage Inventory Carrying Charge

	12 Months Oct 2017- Sept 2018 (000)
RSG Inventory Cost	$ 142,550
BGSS-F Inventory Cost	$ 25,309
BGSS-F Fixed Cost Deferred	$ 13,633
LNG + LPA	$ 2,153
Total Inventory Cost	**$ 183,645**
Total Annual Storage Carrying Cost	**$ 18,868**

Recovery %	**Recovery %**
Balancing	35.00%
Commodity	65.00%

Rate per Dth	MDth	Cost	**$/Dth**
Balancing	151,758	$ 6,604	**$ 0.04352**
Commodity	193,965	$ 12,264	**$ 0.06323**

Revenue Requirement on Gas Production Plants

		12 Months May 17 - Apr 18
May-17		$ 354,985
Jun-17		$ 249,154
Jul-17		$ 193,304
Aug-17		$ 256,638
Sep-17		$ 336,050
Oct-17		$ 400,846
Nov-17		$ 328,947
Dec-17		$ 462,632
Jan-18		$ 515,544
Feb-18		$ 350,065
Mar-18		$ 352,616
Apr-18		$ 259,071
	Total	**$ 4,059,852**
	Sendout - Dth (000)	**151,758**
	Revenue Requirement on Gas Production Plant Charge ($/Dth)	**$ 0.02675**

Gas Supply A&G

	12 Months Oct 18 - Sep 19
Direct Labor & Overhead	$ 7,172,710
Firm Sendout - Dth (000)	193,964.9
Gas Supply A&G Rate	$ 0.03698